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RATINGS SERVICES

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Summary:
AltaLink L.P.

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Summary:
AltaLink L.P.

Credit Rating:	A-/Stable/--

Rationale

The ratings on Alberta based AltaLink L.P. (AltaLink or ALP) reflect Standard & Poor's Ratings Services' opinion of the company's excellent business risk profile and significant financial risk profile. In our view, supportive regulation, predictable cash flows and monopoly electricity transmission assets, with a favorable market framework for transmission companies in the Province of Alberta (AAA/Stable/A-1+) support the ratings. We believe AltaLink's weak credit metrics for the ratings, a large capital program, and large equity requirements from the ultimate owner offset these strengths.

AltaLink is a regulated transmission company wholly owned by AltaLink Investments L.P. (AILP; BBB-/Stable/--). Legal and structural ring-fencing measures permit the ratings on AltaLink to be separated somewhat from those on its parent, but the ratings remain linked. We believe these measures and regulatory oversight restrict AILP's ability to significantly increase cash distributions from AltaLink, and, in the event of an AILP default, provide a significant measure of protection to the operating company. Our ratings methodology begins with a notional consolidated credit quality assessment of 'bbb' at AILP. Based on the strength of the ring-fencing measures neither rating can be more than two notches from the notional consolidated credit quality assessment, and the ratings on AILP and ALP cannot be separated by more than one rating category (three notches). A change in the ring-fencing measures could reduce the ratings separation, but we expect the ratings to remain separated by one rating category. The ratings on ALP and AILP must also be consistent with their stand-alone credit quality. In our view, therefore, a material change in the risk profile of AltaLink, AILP, or AILP on a notional consolidated basis would affect the ratings on both entities. As of Sept. 30, 2012, ALP reported about C$1.7 billion of debt outstanding.

Ongoing supportive regulation is the key influence on the ratings. Key features of the regulatory environment include the long established approach to regulation that uses a cost-of-service methodology that allows full cost recovery with negligible disallowances. AltaLink is not exposed to volume or commodity price risk. The market framework eliminates the company's direct exposure to the credit profile of end use customers since the Alberta Electric System Operator, an agent of the Province of Alberta (AAA/Stable/A-1+), pays ALP its approved annual regulated revenue requirement in equal monthly installments.

We believe AltaLink's credit profile continues to benefit from the company's position as a low-risk monopoly service provider with what we expect is very limited bypass risk.

We expect cash flows to remain stable. Funds from operations (FFO) consist primarily of two components: the return on equity (ROE) and depreciation. The nominal return on equity is determined by multiplying the rate base by the equity thickness (37%) and the 8.75% ROE. The regulator establishes and reviews periodically both the equity thickness and ROE. For tax purposes, the company receives stand-alone treatment from the regulator, allowing it to collect income tax in its revenue requirement. Given its organizational structure as a limited partnership, AltaLink does not pay tax but its owners do. We expect the company to effectively manage its balance sheet during the period of rapid growth.

Forecast credit metrics have limited headroom at the current ratings. Forecast credit metrics for 2012 are about 13% adjusted FFO (AFFO)-to-debt, but decline to about 10% in 2013. The downward pressure is primarily the result of large amounts of capital spending, in particular higher levels of construction work in progress (CWIP) in the rate base. We have assumed gross capex of C$900 million-C$950 million in 2012 and about C$1.5 billion in 2013. Beyond 2013, credit metrics improve somewhat, because large CWIP balances have a more moderate effect on credit metrics.

The large capital program could increase the rate base threefold by 2017. This is placing additional pressure on credit metrics and has led to additional regulatory support. In the most recent General Tariff Application (GTA) decision, the regulator provided additional support to credit metrics by providing CWIP in the rate base and favorable tax support. CWIP in the rate base allows AltaLink to earn a cash return on most of its rate-base investments before project completion. The decision also allows ALP to continue to recover federal taxes using the FIT method, which increases the taxes it includes in its revenue requirement. While CWIP in the rate base provides significant cash flow support, the company will only begin to collect depreciation as projects are completed.

The ratings on AltaLink rely heavily on ultimate unitholder SNC-Lavalin Group Inc.'s (BBB+/Negative/--) continued willingness and ability to inject cash equity into AILP in a timely manner. The large capital program will require significant equity investments from SNC-Lavalin for ALP to maintain deemed regulatory capital structure (37% equity). The total equity requirement from the unitholder could reach C$700 million-C$800 million in the next five years. Given this reliance on the ultimate owner, a decline in our ratings on SNC-Lavalin below the notional consolidated credit quality assessment of AILP would likely affect the ratings on both AILP and ALP.

Key assumptions we have incorporated into our ratings include the following:

- We include in our forecasts regulatory approval of both ongoing CWIP in the rate base and the FIT method of tax calculation for the period of high growth.
- SNC-Lavalin's credit strength will not deteriorate significantly and it continues to provide equity injections on a timely basis and AltaLink's leverage remains in line with the deemed regulatory structure. We also assume the partnership continues to 100% equity-fund goodwill on the balance sheet.
- The company will continue collecting income tax in its revenue requirement but does not pay taxes at ALP or AILP.
- Allowed depreciation rates will remain steady.
- The allowed ROE and deemed equity content the regulator uses to determine ALP's revenue requirement will remain about in line with current levels to support credit metrics, and we expect the partnership to continue to earn its allowed ROE or better.

Liquidity

We believe ALP has "adequate" liquidity as per our criteria. Our assessment incorporates the following expectations and assumptions:

- We expect the company's sources of liquidity, including available capacity on its committed credit lines, to exceed

its uses more than 1.2x in the next six months.
- We expect sources to remain positive, even in the unlikely scenario that EBITDA declines more than 15%.
- We expect AltaLink to continue to have sound relationships with its banks, have satisfactory standing in credit markets, and maintain its prudent approach to financial risk management.
- The company has a debt maturity of C$325 million due in June 2013.

Liquidity sources include about C$1.25 billion of committed credit facilities, of which about C$1.16 billion was available at Sept 30, 2012; FFO of about C$125 million; and equity injections from the parent (which have a track record of being provided quarterly) that we expect to increase commensurate with the level of growth in the capital program. Uses of liquidity consist primarily of capital expenditure, which we estimate at about C$600 million (net of customer contributions).

Outlook

The stable outlook reflects our expectation of timely equity injections from AltaLink's ultimate unit-holder SNC-Lavalin sufficient to maintain the deemed regulatory structure. Any change in SNC-Lavalin's ability or willingness to provide equity injections could result in a negative rating action. Given this reliance on the ultimate owner, a decline in our ratings on SNC-Lavalin below 'BBB' could affect the ratings on both AILP and ALP. While we don't expect it, if we forecast credit metrics below the 10% AFFO-to-debt threshold we associate with the ratings during the period of high capital spending, we could take a negative rating action. An unfavorable regulatory decision affecting AltaLink's business risk profile would also negatively affect the rating. We believe a positive rating action in the next two years is highly unlikely given the company's weak credit metrics, large capital program, and ownership structure.

Related Criteria And Research

- Methodology: Business Risk/Financial Risk Matrix Expanded, Sept. 18, 2012
- Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry, Nov. 26, 2008
- Ring-Fencing A Subsidiary, Oct. 19, 1999

Decision **2004-052**

Generic Cost of Capital

AltaGas Utilities Inc.
AltaLink Management Ltd.
ATCO Electric Ltd. (Distribution)
ATCO Electric Ltd. (Transmission)
ATCO Gas
ATCO Pipelines
ENMAX Power Corporation (Distribution)
EPCOR Distribution Inc.
EPCOR Transmission Inc.
FortisAlberta (formerly Aquila Networks)
NOVA Gas Transmission Ltd.

July 2, 2004

Alberta Energy and Utilities Board

ALBERTA ENERGY AND UTILITIES BOARD
Decision 2004-052: Generic Cost of Capital
AltaGas Utilities Inc.
AltaLink Management Ltd
ATCO Electric Ltd. (Distribution)
ATCO Electric Ltd. (Transmission)
ATCO Gas
ATCO Pipelines
ENMAX Power Corporation (Distribution)
EPCOR Distribution Inc.
EPCOR Transmission Inc.
FortisAlberta (formerly Aquila Networks)
NOVA Gas Transmission Ltd.
Application No. 1271597

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1 INTRODUCTION AND BACKGROUND

On May 6, 2002, the Board received a request from the City of Calgary[1] (Calgary) that the Board institute a proceeding to consider generic cost of capital matters for electric and gas utilities under the Board's jurisdiction. The Board responded to Calgary by letter dated June 6, 2002, indicating that it would be appropriate to await the National Energy Board's (NEB) upcoming decision on rate of return before proceeding to deal with this issue.

On September 30, 2002, the Board distributed a letter (attached as Appendix 3) to interested parties indicating that it had decided to call a generic hearing, pursuant to Section 46 of the *Public Utilities Board Act*[2] (PUBA), to consider cost of capital matters for electric, gas and pipeline utilities under its jurisdiction. Gas transmission (pipeline) and electric transmission companies as well as electric and gas distribution companies under the Board's jurisdiction would be included.

In its letter of September 30, 2002, the Board advised that it intended to hold a pre-hearing meeting to deal with the following issues:

- Determination of the scope of the proceeding and list of issues.
- Determination of procedural matters that might be adopted for such a hearing.

A preliminary list of issues and procedural matters was attached to the September 30, 2002 letter. Interested parties were requested to consider the preliminary list of issues and procedural matters and provide the Board with their written submissions on the appropriateness of each issue or matter, as well as their submissions with respect to additional issues or matters that might appropriately be considered through such a generic proceeding.

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1 In its May 28, 2003 letter, the Board indicated that for purposes of the proceeding, utility companies would be considered as applicants and all other parties as interveners.
2 R.S.A. 2000, c. P-45

On October 7, 2002, the Board issued a Notice of Proceeding (the Notice). By letter of November 20, 2002, the Board advised parties that their written submissions as a result of the Board's September 30, 2002 letter had been sufficient to clarify the parties' positions with respect to the preliminary issues list and that a pre-hearing meeting was therefore not necessary.

By letter dated December 16, 2002, the Board clarified the next steps in the process with respect to a Generic Cost of Capital proceeding. The Board, in establishing this process, gave regard to the submissions, concerns and questions initially filed by parties pursuant to the Board's letter of September 30, 2002 and the reply submissions filed pursuant to the Board's letter of November 26, 2002. The Board set out its rational for consideration of a generic approach to cost of capital issues and established an initial process module (the Standardized Approach Module) to consider the preliminary question of the appropriateness of a standardized approach in the following manner:

> The Board continues to seek out opportunities to improve and streamline the regulatory process and to decrease the overall cost of regulation. The Board is of the view that the cost of capital matters for gas, pipeline, and electric utilities under its jurisdiction are one such area worthy of consideration, particularly given its importance within GTA/GRA proceedings.
>
> The Board notes the amount of regulatory time and accompanying expense that is expended, whereby parties are engaged in seemingly similar cost of capital issues in multiple applications. Applicants and interveners often address these issues through similar investigative, comparative and interpretive methodologies and cost of capital evidence.
>
> The Board is also cognizant of the increasingly heavy utility regulatory schedule that has resulted from electric and gas industry restructuring, new and expanding Board responsibilities, and the general growth and prosperity of the Province.
>
> The Board notes that in previous proceedings, such as the 99/00 Electric GTA, the Board has addressed the uniformity in treatment between utilities on cost of capital matters by hearing the consolidated evidence from all applicants in the same proceeding and rendering a single Board decision (as occurred in Decision U99099). The Board has also attempted to streamline proceedings in other ways, such as the development of policy guidelines like the Negotiated Settlement Guidelines.
>
> In a first module as discussed below, the Board, following submissions from parties, will assess and determine whether or not to proceed further, in a generic process on this issue. This first module will explore the ability and appropriateness of possibly applying a standardized approach in Alberta for all major gas, pipeline and electric utilities under its jurisdiction, whether collectively or on an industry-by-industry basis. Such an approach may magnify the benefits to all parties and enhance the sustainability of the cost of capital determination process, and thereby streamline the regulatory process. The Board wishes to also explore whether the simultaneous airing of views is likely to be more cost-effective than a separate airing of views over a series of proceedings, which may not be linked in evidentiary terms.

The Board then concluded:

> The Board has determined that it will proceed with a written process followed by a Board decision to address the preliminary issue of whether a standardized approach to cost of capital, including return on equity, capital structure and cost of debt, has the potential to achieve reasonable efficiencies while continuing to result in fair and reasonable rates for all stakeholders. As part of the decision, the Board will determine the subsequent steps, if any, for this generic proceeding.

The Board also presented the initial questions to be considered in the Standardized Approach Module and the Board set out the schedule for the Standardized Approach Module.

Having reviewed the written submissions of the parties on the preliminary questions in the Standardized Approach Module, the Board concluded this module on April 16, 2003 by issuing a Notice of Hearing in respect of the continuation of the Generic Cost of Capital proceeding. The Board noted:

> Having considered the submissions received from the above parties, the Board is of the view that a standardized approach to rate of return on equity and capital structure has the potential to achieve certain positive benefits including reduced regulatory costs, while continuing to result in a fair return for all utilities and in just and reasonable rates for all customers. The Board has therefore determined that it will proceed with a generic cost of capital hearing to focus on the possibility of establishing a standardized approach to rate of return on equity and capital structure for all utilities under the jurisdiction of the Board.

The letter also dealt with transitional issues, minimum filing requirements, and set out a scope for the Generic Cost of Capital Proceeding. The Board also established a preliminary schedule that would result in a hearing commencing on November 12, 2003.

By letter dated May 28, 2003, the Board remarked:

> The Board notes that no party objected to the Board’s preliminary scope of the proceeding. Accordingly, the Board confirms the scope for the Generic Cost of Capital Proceeding as set out in Appendix A.

Appendix A of the May 28, 2003 letter outlined the Scope of the Proceeding as follows:

Return on Equity

1. Return on Equity Methodology
2. Allowed 2004 Return on Equity
3. Annual Adjustment Mechanism
4. Process to Review the Return on Equity

Capital Structure

1. Capital Structure for Each Utility Sector
2. Impact on Capital Structure of Utility Holding Company Structures
3. Adjustments to Capital Structure for Non-Taxable Entities
4. 2004 Capital Structure for Each Utility Company
5. Events and Process Which Might Result in Adjustments to Capital Structure

Also in the May 28, 2003 letter, the Board clarified certain transitional issues, refined the minimum filing requirements and indicated that for purposes of the proceeding, utility companies would be considered as applicants and all other parties as interveners. The Applicants are shown below:

Applicant	**Abbreviation**
AltaGas Utilities Inc.	AltaGas
AltaLink Management Ltd.	AltaLink
FortisAlberta (formerly Aquila Networks)	
The ATCO Group of Companies[3]	ATCO
ENMAX Power Corporation (Distribution)	ENMAX
The EPCOR Group of Companies[4]	EPCOR
NOVA Gas Transmission Ltd.	NGTL

A complete list of Participant organizations and their abbreviations is provided in Appendix 1. AltaLink, Aquila and EPCOR collectively referred to themselves as "the Companies". The Board notes that effective May 31, 2004, Fortis Alberta Holdings Inc. (Fortis) completed its acquisition of Aquila and renamed the company FortisAlberta. Any Board decisions or directions in this Decision respecting Aquila should be read as decisions or directions respecting FortisAlberta.

The Board's May 28, 2003 letter also included a Preliminary Schedule shown below:

Notice of Hearing	April 16, 2003
Submissions	May 12, 2003
Reply Submissions	May 20, 2003
Ruling on Procedural and Transitional Issues	May 28, 2003
Utility Applicants Evidence	July 9, 2003
Information Requests (IRs) to Utilities	July 25, 2003
IR Responses from Utilities	August 15, 2003
Intervener Evidence	September 12, 2003
IRs to Interveners	September 26, 2003
IR Responses from Interveners	October 17, 2003
Utility Rebuttal Evidence	November 5, 2003
Hearing Commencement	November 12, 2003

By letter dated, June 24, 2003, the Board clarified the minimum filing requirements, identified electronic filing requirements, and pre-assigned exhibit numbers.

On August 19, 2003, the Board issued a letter advising parties of hearing logistics and a tentative pre-hearing meeting date to resolve scheduling and procedural matters.

By letter dated October 9, 2003, the Board noted that parties generally did not see a need to convene a pre-hearing meeting and accordingly the Board cancelled the meeting that had tentatively been scheduled for October 16, 2003.

[3] ATCO Electric Ltd., ATCO Gas, and ATCO Pipelines
[4] EPCOR Distribution Inc. and EPCOR Transmission Inc.

The Board conducted a public hearing from November 12-14, 2003, November 17-21, 2003 and November 25-27, 2003 at the Board's offices in Edmonton, and from December 1-5, 2003, December 8-12, 2003, December 15-16, 2003, January 5-9, 2004, and January 12-16, 2004, at the Board's offices in Calgary. A list of parties who appeared at the hearing is included in Appendix 1. The Board sat for a total of 33 hearing days.

The Board received written argument on or before February 23, 2004 and written reply on or before April 5, 2004. Accordingly, for purposes of this Decision, the Board considers that the record closed on April 5, 2004.

The Board notes the full participation of a broad range of stakeholders in the proceeding, the large number of parties involved, and the diversity and sophistication of the views represented. The Board also notes the extensive nature of the record of the proceeding which includes pre-hearing submissions, the minimum filing requirements, a thorough set of responses to information requests, detailed expert evidence, hearing transcripts, undertaking responses, and comprehensive argument and reply argument.

Having considered all of the evidence and reviewed the arguments of the interested parties, the Board sets out its Decision with reasons respecting the Generic Cost of Capital Proceeding (Proceeding).

Abbreviations not otherwise defined within the body of the Decision are defined in Appendix 2.

2 SHOULD THE BOARD ADOPT A STANDARDIZED APPROACH TO RATE OF RETURN AND/OR CAPITAL STRUCTURE?

2.1 NGTL Jurisdictional Objection

NGTL submitted that the Board does not have the jurisdiction to implement a formula approach to establish a fair return for NGTL.

NGTL submitted that the specific jurisdiction of the Board in respect of the determination of the fair return for any gas utility comes only from section 37 of the Alberta *Gas Utilities Act*[5] (GUA). Section 37 reads as follows:

> 37(1) In fixing just and reasonable rates, tolls or charges, or schedules of them, to be imposed, observed and followed afterwards by an owner of a gas utility, the Board shall determine a rate base for the property of the owner of the gas utility used or required to be used to provide service to the public within Alberta and on determining a rate base it shall fix a fair return on the rate base.
>
> (2) In determining a rate base under this section, the Board shall give due consideration
>
> a. to the cost of the property when first devoted to public use and to prudent acquisition costs to the owner of the gas utility, less depreciation, amortization or depletion in respect of each, and
>
> b. to necessary working capital.

[5] R.S.A. 2000, c. G-5

(3) In fixing the fair return that an owner of a gas utility is entitled to earn on the rate base, the Board shall give due consideration to all facts that in its opinion are relevant.

NGTL submitted that based on the wording of subsection 37(1), the Board does not have jurisdiction to fix a fair return for a gas utility "*unless and until it has determined a rate base"* for that gas utility. The rate base will vary from year to year, and the Board must determine the rate base for a particular period before it can determine a fair return for that period. NGTL argued that the Board cannot make a pre-determination of the fair return for a particular period, using a formula, and then apply that return to whatever rate base it subsequently determines is appropriate in respect of that same period. NGTL submitted that application of a formulaic return to a rate base that has yet to be determined would fetter the discretion of future Board panels and is not permitted by the statute.

NGTL also considered the wording of section 45 of the GUA, which provides:

45(1) Instead of fixing or approving rates, tolls or charges, or schedules of them, under sections 36(a), 37, 40, 41, 42 and 44, the Board, on its own initiative or on the application of a person having an interest, may by order in writing fix or approve just and reasonable rates, tolls or charges, or schedules of them,

(a) that are intended to result in cost savings or other benefits to be allocated between the owner of the gas utility and its customers, or

(b) that are otherwise in the public interest.

(2) The Board may specify terms and conditions that apply to an order made under this section.

NGTL submitted that section 45 of the GUA was implemented to permit approval of negotiated settlements and does not empower the Board to establish a formulaic approach to fair return. NGTL submitted that by its terms, section 45 relates to "rates, tolls or charges", not to return.

NGTL also submitted that the fact it did not raise the jurisdiction issue in the first module of this proceeding does not prohibit it from raising the issue in argument.

Jurisdiction to Interpret the GUA Provisions

The NGTL position in effect poses the following question: "Does the Board have jurisdiction to fix a fair return for a gas utility through a standardized approach based on a formula?" (the Jurisdictional Question) Before the Board can address this question, it must first determine if it has jurisdiction to interpret the subject provisions of the GUA. The Board finds it does have such jurisdiction on the basis of the reasons stated below.

The Board notes section 36(1)(a) of the PUBA which provides:

The Board has all the necessary jurisdiction and power

(a) to deal with public utilities and the owners of them as provided in this Act;

The Board further notes section 36(2) of the PUBA, which provides:

> In addition to the jurisdiction and powers mentioned in subsection (1), the Board has all necessary jurisdiction and powers to perform any duties that are assigned to it by statute or pursuant to statutory authority.

In order for the Board to perform the duties assigned to it pursuant to sections 37 and 45 of the GUA, the Board must be able to interpret and apply the wording of the legislation.

Board also notes the provisions of section 38 of the PUBA, which provides:

> The Board may, as to matters within its jurisdiction, hear and determine all questions of law or of fact.

The interpretation of the Board's governing legislation is a question of law or of fact.

The Board further notes the decision of the Alberta Court of Appeal in *ATCO Electric Ltd. v. Alberta* (Energy and Utilities Board) [2003] A.J. No. 1634, (2003) 339 A.R. 152 as a recent acknowledgment of the ability of the Board to construe its own legislation.

Accordingly, the Board finds that the ability to interpret sections 37 and 45 of the GUA is within its jurisdiction.

Is the Matter One of Interpretation?

Next, the Board must determine if the Jurisdictional Question is a matter of interpretation of the relevant provisions.

The Board finds that the Jurisdictional Question is a question of law or of fact, the answer to which is dependant on an interpretation of sections 37 and 45 of the GUA and the relevant legislation taken as a whole. Having found that the interpretation of its own legislation is within the Board's jurisdiction, the provisions of section 38 of the PUBA provide the Board with the authority to settle questions of law or of fact within that jurisdiction.

Accordingly, the Board finds that it has the jurisdiction to address the Jurisdictional Question and that the question is matter of law or of fact, dependant on the interpretation of the relevant statutory provisions.

The Jurisdictional Question

With respect to the Jurisdictional Question itself, the Board finds that the proper interpretation of section 37 of the GUA would allow the Board to determine the capital structure for the relevant test period (2004 or 2005) for each gas utility under its jurisdiction by way of a generic proceeding and to establish a standardized approach based on a formula for determining the return on common equity for gas utilities.

The Board makes this finding for the following reasons:

1. In this Decision, the Board has established a standardized approach to setting a rate of return on common equity (ROE), which is adjusted annually by way of a formula, subject to the limitations set out herein. In addition, this Decision has established the capital structure for each utility for the relevant test period. NGTL objects to the adoption of a formula in setting a fair return that determines a result independently, and prior to, the determination of rate base. Although, the Board does not agree with NGTL's submissions in this regard, it does note and agrees with NGTL's explanation of the elements of fair return when it states on page 2 of its Written Evidence, Exhibit 013-04:

   > The fair return on rate base is fixed by the regulator through determinations of the deemed utility capital structure, the reasonable cost of debt capital and the fair return on equity (ROE) capital.

   In this Decision, the Board has not determined all elements of the fair return for a Utility. The Board has implemented a formula in connection with the determination of ROE with an annual adjustment mechanism. The Board has also set the capital structure for utilities in the Proceeding for the relevant test period. It has not dealt with the cost of debt capital. Further, it has left open the possibility that a utility may request changes in its capital structure with respect to subsequent test periods by way of future general rate applications where circumstances so warrant. An applicant is also free to apply to the Board to review the ROE formula in the manner provided for in this Decision. Even without an application by a particular party, the ROE formula will be subject to review in certain circumstances and in any event will be considered for review after five years.

   This Decision approves a formula and adjustment mechanism for ROE, being one element of a fair return, following a long and complex public process. The result furthers regulatory and cost efficiencies while ensuring fairness to parties and future safeguards to address material changes in circumstance. ROE is not the only element required to determine a fair return. On its own, ROE is not determinative of the fair return component of a utility's revenue requirement. It is only when the ROE is combined with the other elements of the fair return and then applied to the rate base that it is included within the revenue requirement of a utility and subsequently in customer rates. Accordingly, the ROE determined in accordance with the formula approved by this Decision is not included within rates until the remaining relevant elements of a fair return and the rate base applicable for a particular period have been determined. With respect to a particular utility, it is the individual panel(s) of the Board seized with the responsibility of making determinations in respect of the appropriate revenue requirement for a particular test period and with fixing just and reasonable rates which must make the final determination that the revenue requirement, inclusive of all elements of a fair return when combined with the ROE determined in this Proceeding, is appropriate and that the rates are just and reasonable.

   The Board also notes that the embedded cost or appropriateness of existing long term debt is not reconsidered each time that the rate base is determined. Individual long term debt issuances are considered by the Board either when the debt is incurred, on a pre-approval basis, or within a GRA/GTA proceeding. Once approved, long term debt costs normally continue in the revenue requirement for the duration of the debt instrument

2. The Board notes and agrees with the submission of CAPP at page 2 of its Reply Argument that the mechanical approach proposed by NGTL to interpreting the GUA would leave the Board without clear authority to utilize the ROE mechanism in its determination of what is a fair return. In this regard, the Board also notes the decision of the Supreme Court of Canada in *Bell Canada v. Canada* (Canadian Radio-Television and Telecommunications Commission), [1989] 1 S.C.R. 1722 at page 1756 where the Court held:

> The powers of any administrative tribunal must of course be stated in its enabling statute but they may also exist by necessary implication from the working of the act, its structure and its purpose. Although courts must refrain from unduly broadening the powers of such regulatory authorities through judicial law-making, they must also avoid sterilizing these powers through overly technical interpretations of enabling statutes.

   The Board also notes the decision of the Supreme Court of Canada in *ATCO Ltd. v. Calgary Power* [1982] 2 S.C.R. 557, wherein the Court discusses the nature of the powers of the Board to carry out its responsibilities under the PUBA and the GUA. At page 576, the Court stated:

> It is evident from the powers accorded to the Board by the legislation in both statutes mentioned above that the legislature has given the Board a mandate of the widest proportions to safeguard the public interest in the nature and quality of the service provided to the community by the public utilities.

   The Board agrees with the following submission of CAPP appearing at page 2 of its Reply Argument:

> In CAPP's submission, the GUA is properly interpreted as prescribing a form of regulation, namely, rate base/rate of return regulation based on depreciated book cost plus working capital. The GUA does not prescribe how the Board is to determine a fair return and does not prescribe the exact order in which decisions can be made. Nothing precludes the Board from adopting an approach in which rate base is determined independently whatever the level of return and in which return is determined independently of rate base or other cost items such as debt cost. All that is required is that the rates that result would be in accord with the Act, namely, be based on rate base/rate of return among other things.

3. The Board notes that section 45 of the GUA does not require the Board to consider rate base before fixing or approving rates. The Board notes that such rates would include a fair return component either explicitly or implicitly. The Board must consider whether such rates are in the public interest. A consideration of the resultant rates in the context of the public interest is consistent with fixing just and reasonable rates pursuant to section 37 of the GUA and with the Board's approach in this Decision of establishing a just and reasonable standardized approach to establishing rate of return on equity.

With respect to regulatory efficiency, economy of process, cost effectiveness, and procedural fairness to all parties, the Board notes CAPP's submission at page 2 of its Reply Argument that NGTL failed to question the Board's jurisdiction in its submissions on the Standardized Approach Module of the proceeding. The issue that was addressed in that module was whether or not the Board should proceed further with a generic cost of capital process and the ability and appropriateness of possibly adopting a standardized approach. While CAPP acknowledged that jurisdiction couldn't be conferred by consent, it did call into question the merit of the argument.

The Board agrees with CAPP that the appropriate time to challenge the jurisdiction of the Board to establish a standardized approach to elements of a fair return would have been during the submissions leading to the Board's decision on April 16, 2003 to proceed with the generic cost of capital hearing following the Standardized Approach Module. In its letter of December 16, 2002 wherein the Board established the process for the Standardized Approach Module, the Board stated:

> The Board has determined that it will proceed with a written process followed by a Board decision to address the preliminary issue of whether a standardized approach to cost of capital, including return on equity, capital structure and cost of debt, has the potential to achieve reasonable efficiencies while continuing to result in fair and reasonable rates for all stakeholders. As part of the decision, the Board will determine the subsequent steps, if any, for this generic proceeding.

The Board's letter requested parties to respond to specific questions in their submissions. Question 6 requested parties to respond to the following question:

> Would it be correct to consider a standardized approach to setting:
> - Utility equity rate of return;
> - Utility capital structure; and
> - Utility cost of debt,
>
> for all types of gas and electric utilities under the Board's jurisdiction?

NGTL did not raise its jurisdictional concerns in its response to the Board's request for submissions on this first module, nor did NGTL give notice of jurisdictional concerns following the Board's initial module decision to continue with the generic cost of capital proceeding hearing process. In fact, NGTL actively participated in the proceeding, filing evidence, asking information requests of other parties, presenting 3 panels of witnesses for cross-examination and cross examining other parties.

NGTL raised its jurisdictional concerns for the first time in written argument. The Board considers that the appropriate time to have raised the subject jurisdictional concerns was during the initial module process.

2.2 Should the Board Adopt a Standardized Approach?

AltaGas supported a standardized approach to ROE and capital structure, but only if the starting points recommended by Ms. McShane were implemented. Similarly, the Companies had no objection to the adoption of a rate of return adjustment formula providing that the formula was appropriate and contained reasonable starting point values.

ENMAX had reservations regarding the adoption of a generic approach and submitted that a generic approach must be flexible enough to account for differences between utilities and to consistently meet the comparable investment, capital attraction and financial integrity criteria.

ATCO and NGTL opposed a standardized approach to ROE and capital structure. ATCO submitted that a formula approach would not add to consistency, would not add to predictability and would not necessarily reduce regulatory lag.

As discussed in the previous section of this Decision, NGTL submitted that the Board does not have the jurisdiction to implement a formula approach to establish a fair return for NGTL. NGTL also submitted that even if the Board could legally implement a formula approach for NGTL, practical considerations should preclude the Board from doing so; and furthermore, if the Board establishes a formula for NGTL, then the mitigating measures suggested by Dr. Kolbe were essential.

All of the interveners supported a generic approach. Benefits cited for a generic approach generally included improved efficiency of the regulatory process in Alberta, greater consistency between utilities, and greater certainty and predictability of utility returns. Many interveners noted that the NEB and other Canadian regulators have had generic approaches in place for many years, and submitted that there was no reason why a generic approach could not also be used in Alberta.

The Board notes that some Applicants and all interveners supported a generic approach to ROE and capital structure. The Board considers that a generic approach would improve regulatory efficiency. As set out above, the Board does not agree with NGTL that there are legal impediments to the adoption of a generic process for gas utilities. The Board notes that other regulators have successfully implemented generic approaches to ROE and capital structure. Therefore, the Board is not persuaded that there are any practical impediments to the adoption of a generic process for utilities regulated by the Board.

Accordingly, the Board finds that the evidence in the Proceeding indicates that implementation of a generic approach is in the public interest and accordingly, the Board will implement a generic approach to ROE and capital structure. In the following sections, the Board will address the issues associated with the determinations necessary to appropriately implement this approach.

3 LEGISLATIVE AND JUDICIAL FRAMEWORK

In its letter of April 16, 2003, wherein the Board indicated its decision to proceed with a generic hearing, the Board outlined the purpose of the proceeding in the following manner:

> Having considered the submissions received from the above parties, the Board is of the view that a standardized approach to rate of return on equity and capital structure has the potential to achieve certain positive benefits including reduced regulatory costs, while continuing to result in a fair return for all utilities and in just and reasonable rates for all customers. The Board has therefore determined that it will proceed with a generic cost of capital hearing to focus on the possibility of establishing a standardized approach to rate of return on equity and capital structure for all utilities under the jurisdiction of the Board.

This section reviews the legislative and judicial framework that the Board has had regard to in reaching the determinations made herein.

3.1 Legislation

Authority to Hold an Inquiry

By letter dated September 30, 2002, the Board indicated that it had decided to call a generic hearing pursuant to its powers to hold an inquiry under section 46 of the PUBA to consider cost of capital matters for electric, gas and pipeline utilities under its jurisdiction. Section 46 provides the Board with the necessary statutory authority to commence the process that has culminated in this Decision.

The Board also notes that no party has asserted that the Board lacks the jurisdiction to conduct this generic proceeding. The Board notes however, the assertion of NGTL that the Board lacks the jurisdiction to establish a fair return for a gas utility unless and until it has determined a rate base for that gas utility pursuant to subsection 37(1) of the GUA. The Board has dealt with this objection in Section 2 of this Decision.

Authority to Set Fair Return

The Board's jurisdiction to set rates and in particular, a fair return for the utilities under its jurisdiction, is found in the following statutes:

- PUBA, including Part 2, Division 1 and in particular section 90 thereof;
- GUA, including Part 4 thereof and in particular section 37 thereof;
- *Electric Utilities Act*[6] (EUA), including Part 9 thereof and in particular section 122 thereof.

3.2 Relevant Judicial Decisions

Many of the parties quoted passages from decisions of the Supreme Court of Canada and of the U.S. Supreme Court to delineate the relevant judicial guidance for the Board when embarking on a process to establish a fair return for the utilities under its jurisdiction. The Board has provided below extracts from the most frequently cited decisions. These seminal decisions have, in turn, influenced subsequent decisions referred to by the parties.

In *Northwestern Utilities v. the City of Edmonton* [1929] S.C.R. 186; [1929] 2 DLR 4 (*NUL 1929*), the Supreme Court of Canada found at page 192:

> The duty of the Board was to fix fair and reasonable rates: rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested. By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise. In fixing this net return, the Board should take into consideration the rate of interest which the company is obliged to pay upon its bonds as a result of having to sell them at a time when the rate of interest payable thereon exceeded that payable on bonds issued at the time of the hearing. To properly fix a fair return the Board must necessarily be informed of the rate of return which money would yield in other fields of investment. Having gone into the matter fully in 1922, and having fixed 10% as a fair return under the conditions then existing, all the Board needed to know, in

6 S.A. 2003, c. E-5.1

> order to fix a proper return in 1927, was whether or not the conditions of the money market had altered, and, if so, in what direction, and to what extent.[7]

In *Federal Power Commission et al. v. Hope Natural Gas Company*, 320 U.S. 591 (1944) (*Hope*), the U.S. Supreme Court found at page 591:

> The rate-making process under the Act, i.e. the fixing of 'just and reasonable' rates, involves the balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline case that 'regulation does not insure that the business shall produce net revenues'. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view, it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. The conditions under which more or less might be allowed are not important here. Nor is it important to this case to determine the various permissible ways in which any rate base on which the return is computed might be arrived at. For we are of the view that the end result in this case cannot be condemned under the Act as unjust and unreasonable from the investor or company viewpoint.[8]

In *Bluefield Waterworks and Improvement Company v. Public Service Commission of the State of West Virginia et al.*, 262 U.S. 679 (1923) (*Bluefield*), the United States Supreme Court found at page 692:

> The company contends that the rate of return is too low and confiscatory. What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgement, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit to enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.[9]

The Board notes that no party took issue with the general consensus that in order for a return to be fair, it must meet the tests of "comparable investment", "capital attraction" and "financial integrity" described in the above decisions. The Board concurs that the above decisions are the most relevant judicial authorities with respect to the establishment of a fair return for regulated utilities.

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7 *NUL 1929*, at 192-193
8 *Hope*, at 603
9 *Bluefield*, at 692

4 RETURN ON EQUITY

4.1 Common Return on Equity for all Utilities versus Utility-Specific ROEs

In this section, the Board will address whether there should be a common ROE applicable to all Applicants or whether there should be utility-specific ROEs. The Board will address the potential use of an adjustment mechanism for ROE, which could be applicable to either a common ROE or to utility-specify ROEs, in a later section of this Decision.

The following table summarizes the positions of the parties with respect to the issue of a common ROE applicable to all Applicants versus utility-specific ROEs:

Table 1. Common ROE versus Utility-Specific ROE Requirements

Recommended or Not Opposed to Common ROE	Opposed to Common ROE – Favoured Utility–Specific ROE
AltaGas ATCO Calgary CAPP Cargill CG ENMAX IPCAA IPPSA	Companies NGTL

Parties who supported a common ROE indicated that differences in business risk should be reflected through adjustments to capital structure. Certain of these parties also indicated that in the event that adjusting capital structure was not adequate to reflect the business risk for a particular Applicant, the common ROE could be adjusted for that particular Applicant. These parties generally took the position that the onus should be on each individual Applicant to establish the need for an exception to the common ROE. Interveners took the position that none of the Applicants had established such a need. ATCO, while supporting a common ROE, submitted that an exception was required for ATCO Pipelines.

The Board does not consider that persuasive arguments were raised against the use of a common ROE. The Board disagrees with NGTL’s view that a common ROE fails to recognize the impact of leverage on the cost of equity and with the Companies’ view that companies in the same industry may have different investment risks that require different ROEs. In the Board’s view, a common ROE approach can accommodate these differences, by adjusting for any material differences in investment risk that would otherwise occur, through an adjustment to the capital structure, or, in exceptional circumstances, through a utility-specific adjustment to the common ROE.

The Board will therefore establish a common, or generic, ROE to be applied to all Applicants. The Board will address the need for any utility-specific adjustments to the common ROE in the capital structure section of this Decision.

In this regard, the Board considers that unique utility-specific adjustments to the common ROE should only be made in exceptional circumstances where adjusting capital structure alone is not sufficient to reflect the investment risk for a particular Applicant.

4.2 ROE Methodology and 2004 ROE

4.2.1 Introduction

The following table summarizes the 2004 ROE recommendations of the expert witnesses:

Table 2. 2004 ROE Recommendations by Expert Witnesses

Witness (Sponsoring Party)	Applies to	ERP Tests ROE Results (%)	DCF Test ROE Results (%)	CE Test ROE Results (%)	2004 Recommended ROE (%)
Ms. McShane[10] (AltaGas/ATCO)	All except ATCO Pipelines	10.5-10.75	11.0-11.25	No less than 13	11.0-11.5
Dr. Evans[11] (Companies)	Companies	9.8-10.4		12 (for ETI)	10.5-11.25
Dr. Neri[12] (ENMAX)	ENMAX	10.05-11.65	10.5-10.95		11.5
Drs. Kolbe & Vilbert[13] (NGTL)	NGTL	11	10.3-14.1,[14] used as check		11 at 40% common equity
Dr. Booth[15] (Calgary/CAPP)	All	8.12	Confirmed ERP of 8.12 was fair	9-10, used as check	8.12
Drs. Kryzanowski & Roberts[16] (CG)	All	8.05			8.05

The Board notes that no party relied directly on an ATWACC approach to setting a fair return for utilities. For the ERP results in the above table, all experts relied at least in part on the CAPM form of the ERP test. Most experts also relied in part on various other tests, including other forms of the ERP test, the DCF test, the CE test, and other measures of comparable investment. The Board will consider each of these approaches in the following sections.

4.2.2 After Tax Weighted Average Cost of Capital

NGTL's evidence (Exhibit 013-03) states:

> In the first phase of this proceeding, NGTL recommended that the Board cast the issues net broadly enough to include methodologies other than the traditional. While the EUB Notice of Hearing does not explicitly exclude the ATWACC approach, it does so implicitly by establishing the scope of the proceeding in capital structure/return on equity terms. NGTL has therefore focused its evidence on the traditional methodology, subject to the fundamental precepts that the cost of equity depends on the amount of financial risk of the company, and that financial risk changes with capital structure.[17]

[10] Exhibit 005-10-2, Evidence of Kathleen McShane, page 5
[11] Exhibit 003-03, Evidence of Robert E. Evans, pages 24 and 25 and Exhibit 012-01, Evidence of Robert E. Evans Supplement C page C-20
[12] ENMAX, Argument, page 16
[13] NGTL Argument, page 20
[14] Exhibit 013-06, Evidence of Michael J. Vilbert, page 52
[15] Calgary/CAPP Argument, page 17 and Exhibit 016-11(a), pages 14 and 36
[16] CG Argument, page 47
[17] Exhibit 013-03, NGTL Evidence, page 5, line 15

In its Argument, NGTL stated:

> In the first phase of this proceeding, NGTL recommended that the Board cast the issues net broadly enough to include methodologies other than the traditional. The EUB Notice of Hearing implicitly excluded the ATWACC approach by establishing the scope of the proceeding in capital structure/return on equity terms.[18] (Footnotes excluded)

Notwithstanding NGTL's statements that the Board had not explicitly excluded the ATWACC approach, under cross-examination NGTL confirmed that it had not requested the Board to consider the ATWACC approach to cost of capital matters. The following dialogue occurred during examination by Board Counsel of NGTL's witness, Mr. Brett:

> Q………..Are you in the context of your evidence, suggesting that the Board should consider ATWACC and ATWACC methodology in terms of coming up with a fair return for NGTL?
>
> A. MR. BRETT:…..We have not asked the Board to set tolls using an ATWACC methodology which, for example, is what we did in the fair return. What we have indicated is that leverage matters and that capital structure impacts the return that is required; and to our mind, in order to determine that interrelationship, you have to be cognizant of the overall return on capital.
>
> Q……….. So, again, just to be clear, you're not asking the Board to consider ATWACC in terms of how it would set a fair return; moreover, it is being suggested by the company that it is one of the tools it uses as, perhaps, a check in terms of what a fair return would be; would that be a fair statement?
>
> A. MR. BRETT: …..I think what I said, and what I intended to say, is we have not asked the Board to use a return on capital or ATWACC for setting a revenue requirement. We have applied for the traditional ROE on equity thickness.[19]

Given the submissions at the beginning of the proceeding, the Board's written views on the scope for the proceeding and the examination during the Hearing, the Board does not agree with NGTL's stated interpretation of the Board's Notice of Hearing dated April 16, 2003. The Board considers it clear that the Notice of Hearing did not limit, either explicitly or implicitly, any submissions or evidence that a party might wish to present in respect of the approach or the methodology that a party would urge upon the Board to consider in making a determination of an appropriate fair return.

In the Notice of Hearing, the Board stated:

> Having considered the submissions received from the above parties, the Board is of the view that a standardized approach to rate of return on equity and capital structure has the potential to achieve certain positive benefits including reduced regulatory costs, while continuing to result in a fair return for all utilities and in just and reasonable rates for all customers. The Board has therefore determined that it will proceed with a generic cost of capital hearing to focus on the possibility of establishing a standardized approach to rate

[18] NGTL Argument, page 18
[19] Transcript, Volume 20, pages 2777- 2778

> of return on equity and capital structure for all utilities under the jurisdiction of the Board.[20]

It is clear that the Notice refers only to the possibility of establishing a standardized approach to rate of return on equity and capital structure for utilities. Further, in the Board's letter of May 28, 2003, the Board clarified that it had not already made a final determination to adopt a standardized approach to rate of return and capital structure.

> The Board confirms that it expects to adopt a standardized approach to rate of return and capital structure. The Board decided to continue with a generic cost of capital hearing based on a record that supports the overall merits of a standardized approach to rate of return and capital structure. **The Board wishes to emphasize, however, that the approach ultimately adopted by the Board may differ between industries or on some other appropriate basis.**[21] (Emphasis added)

The language in the Board's Notice reinforced the decision of the Board to proceed to a hearing to consider a standardized approach to rate of return and capital structure. However, the last sentence of the paragraph clarified to parties that a standardized approach to rate of return and capital structure may not be found to be appropriate and that the Board remained open to other cost of capital approaches.

The Board also notes the statement of NGTL in their evidence:

> Properly applied, ATWACC and the traditional methodology should yield similar results.[22]

This statement by NGTL clearly indicates its position that the results obtained under one methodology for determining a fair return should be similar to the results obtained through the other methodology, when each methodology is properly applied. The Board also notes that the NGTL evidence and argument provided submissions on an appropriate return on equity and capital structure for NGTL as well as the ATWACC equivalent.[23]

4.2.3 CAPM Test

As noted above, all experts relied at least in part on the CAPM form of the ERP test. The Board will address other forms of the ERP test relied on by the experts in this Proceeding in the next section of this Decision.

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20 EUB Notice of Hearing, April 16, 2003
21 Board's letter of May 28, 2003
22 Exhibit 013-03, NGTL Evidence, page 5
23 For example Exhibit 013-03, NGTL Evidence, pages 4 and 6 and NGTL Argument pages 19, 89, 92 and 117

The following table summarizes the CAPM recommendations of the expert witnesses:

Table 3. CAPM Recommendations[24]

Witness (Sponsoring Party)	Risk-free Rate (%)	MRP (%)	Beta	Flotation Allowance (%)	ROE (%)
Ms. McShane (AltaGas/ATCO)	5.75	6.0	0.60-0.65[25]	0.50	10.0
Dr. Evans (Companies)	5.60	5.75	0.60	0.75	9.8
Dr. Neri (ENMAX)	6.15	6.5	0.60	0.50[26]	10.5[27]
Drs. Kolbe & Vilbert[28] (NGTL)	5.65	5.5	0.61	0.50[29]	9.5[30]
Dr. Booth (Calgary/CAPP)	5.5	4.5	0.45-0.55[31]	0.50	8.25
Drs. Kryzanowski & Roberts (CG)	5.6	4.7	0.50	0.10	8.05

Risk-Free Rate

A forecast of the long-Canada bond yield is traditionally used as the risk-free rate, for CAPM purposes. The Board notes that none of the experts suggested departing from this practice.

The Board notes from the above table that the range of risk-free estimates was from 5.5-6.15%. Dr. Booth's (sponsored by Calgary/CAPP) estimate of 5.5% was at the low end of the range. However, CAPP noted in argument that the November 2003 Consensus Forecast used by the NEB for its 2004 ROE determination resulted in a forecast of the long-Canada bond yield used by the NEB for 2004 of 5.68%, which would increase CAPP's 2004 ROE recommendations.

The Board notes that Dr. Neri's (sponsored by ENMAX) estimate of 6.15% is significantly higher than any other estimate. Excluding both Dr. Booth's and Dr. Neri's estimates would result in a range of risk-free estimates of 5.60-5.75%.

The Board considers this range of 5.60-5.75% to be a reasonable range for the 2004 risk-free rate, with a midpoint of 5.68%.

The Board notes that this midpoint of 5.68% is the same as the risk-free rate used by the NEB for 2004, which was based on the November 2003 Consensus Forecast. The Board considers the use of a risk-free rate based on the November 2003 Consensus Forecast is consistent with the formula to adjust the generic ROE that the Board establishes in a later section of this Decision. Use of the November 2003 Consensus Forecast is also consistent with the objective of establishing utility revenue requirements based on forecasts made in advance of the test year.

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24 Cargill Argument, page 15, except as otherwise indicated
25 Exhibit 005-10-2, Evidence of Kathleen McShane, page 30
26 The Board has added the 0.50% flotation cost indicated in the CAPP/Calgary Argument at page 7
27 Ibid.
28 Exhibit 013-06, Table No. MJV-10, panel B, "Average C" ("Averages A & B" are virtually identical to C) and Exhibit 013-06, page 39
29 Flotation costs assumed to be 50 basis points; NGTL considered flotation costs as a valid cost, but did not make a specific recommendation. NGTL Argument, page 55
30 Ibid.
31 Exhibit 016-11(a), Evidence of L.D. Booth, page 23

Therefore, the Board finds that an appropriate risk-free rate for 2004 is 5.68%.

MRP (Market Risk Premium)

The Board notes that some parties, including IPCAA, argued that the arithmetic average MRP overstates the returns that investors have received or can expect to receive in the future. In the Board's view, when a forecast is based on the historic average, the arithmetic average MRP represents the best estimate of the short-term return and the geometric average represents the best estimate of the long-term return. The Board has not been persuaded that it should change its practice of using the arithmetic average. Consequently, the Board will maintain its practice of using the arithmetic average rather than the geometric average.

The following table summarizes the evidence on the average arithmetic MRPs in Canada and the U.S. for various time periods:

Table 4. Historical Arithmetic Canadian and U.S. MRPs

	Canada	U.S.
1802-1998[32]		4.7
1900-2002[33]	5.5	6.4
1924-2002[34]	5.0	
1926-2001[35]		7.0
1936-2002[36]	4.7	
1947-2002[37]	5.0	6.7
1957-2002[38]	2.3	4.2

In this Proceeding, a number of concerns were raised regarding the use of historic data as a reasonable estimate for the future MRP:

1. Dr. Booth indicated that Canadian data prior to 1956 should not be used. However, Dr. Booth indicated that the Canadian equity risk premium since 1956 has been only about 2.3%. Dr. Booth then adjusted this figure upward to 4.5%, to take into account the influence of earlier data, the unexpected performance of the bond market, and the U.S. data.[39] This indicates that Dr. Booth was unable to rely on the historic data without a material adjustment;
2. ATCO noted a number of problems in using Canadian historical data including structural changes in the economy, the recent impact of a few large firms on the market proxy and the need to consider U.S. data;[40] and
3. CG noted that the current equity risk premium could be expected to be about 1% lower than the historical equity risk premium due to current lower trading costs.[41]

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32 Exhibit 016-11(a), Evidence of L.D. Booth, page 33
33 Exhibit 017-05(a), Evidence of Kryzanowski and Roberts, Schedules, Schedule 4.3 and 4.5
34 Exhibit 016-11(a), Evidence of L.D. Booth, Schedule E1 (Canadian Institute of Actuaries Data)
35 Exhibit 012-01, EPCOR Transmission, Direct Evidence and Supplements of Robert E. Evans, Dec. 2002, Supplement C, page C-10
36 Exhibit 009-02(b) Schedule 5 (Canadian Institute of Actuaries data)
37 Exhibit 005-10-2, Table 4, page 27
38 Exhibit 016-11(a), Evidence of L.D. Booth, Appendix E, Schedule E1 and Appendix F, Schedule F2
39 Exhibit 016-11(a), Evidence of L.D. Booth, page 24
40 ATCO Argument, pages 25 and 26
41 CG Argument, page 31

In the Board's view, a reasonable approach is to consider the longer-term average historic Canadian equity risk premium and then adjust this upward or downward based on the Board's judgment and the Board's assessment of the evidence regarding the prospective outlook for the equity risk premium.

In the Board's view, in general, the present Canadian market already reflects the impact of U.S. data based on the current degree of North American market integration. Participants make market trade-offs in their decisions on how to participate in the various markets around the world. The present high degree of integration would not have been fully reflected historically, accordingly, the Board considers that the U.S. historical MRP should be considered as one of many factors in applying judgment to adjust the Canadian historic MRP. The Board notes Dr. Booth's evidence that U.S. MRPs need to be tax-adjusted and that therefore U.S. market returns are biased high for Canada, but still provide a ceiling for Canadian estimates.

The Board notes from Table 3, that the range of the experts' recommended MRP estimates was from 4.5-6.5%, with a midpoint of 5.5%. The Board also notes from Table 4 above that the historic arithmetic risk premium in Canada has been 4.7-5.5% for those periods ending in 2002 that provide 50 or more years of history. In the Board's view, the historic evidence, along with some recognition of the higher U.S. figures, supports the midpoint of the experts' estimates at 5.5%.

Considering all of the above, the Board finds that an MRP of 5.5% is appropriate.

The Board also notes that this midpoint of 5.5% is consistent with the MRP used by the Board in its most recent rate of return determinations.[42]

Beta

The Board notes that there was general agreement that use of actual data from very recent years, to calculate beta, would under-estimate the prospective beta due to the technology-related market bubble and subsequent collapse, and that there was also general agreement that beta is a relative risk factor that requires judgment.

The Board notes from Table 3 that the range of beta estimates recommended by the expert witnesses was from 0.45-0.65. Dr. Booth's estimate of beta of 0.45-0.55 was the lowest estimate in the range. The next lowest estimate was 0.50, proposed by Dr. Kryzanowski (sponsored by CG). The Board also notes from the argument of Calgary/CAPP that the beta of 0.55 recently used by the Board[43] was at the top of Dr. Booth's range, but "is well within normal estimation error".[44] The Board also notes that the high estimate of 0.65 was partially based on adjusted U.S. data and partially based on a relative risk calculation that utilized standard deviations and not the more usual regression analysis calculation.[45]

Based on the above, the Board finds that a reasonable estimate of beta, or the relative risk factor of utilities versus the overall equity market, is 0.55.

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42 Includes Decisions 2003-63, 2003-71, 2003-72 and 2003-100
43 Decisions 2003-63, 2003-71, 2003-72 and 2003-100
44 Calgary/CAPP Argument, Section 4.2.3.2, page 15
45 Exhibit 008-01, ATCO Pipelines 2003-2004 Application, Evidence of Kathleen McShane, pages 44-47 of 63

The Board also notes that this estimate of beta of 0.55 is consistent with the value that the Board has assigned to beta in its most recent rate of return determinations.[46]

Flotation Cost Allowance

The Board notes that all parties, except the Companies and CG, recommended or were not opposed to a 0.50% allowance for flotation costs and financing flexibility.

The Board notes that CG and CAPP suggested that an alternative to an ongoing flotation allowance was to expense the costs of flotation. CG proposed that this expense could be amortized over 50 years. In the Board's view, there was limited support for changing its past approach to flotation costs.

The Board notes that the Companies argued that the flotation allowance should be increased to 0.75%, based on the increased capital markets volatility. However, the Board considers that there is merit in CG's argument that the apparent higher volatility in the markets was due to a rapid increase in listings by smaller and more risky firms and was not due to the utility sector.[47] The Board is therefore not convinced that a change is required to the 0.50% flotation cost allowance used in recent decisions.

Based on the above, the Board finds that continuation of a 0.50% allowance for flotation costs and financing flexibility is appropriate.

CAPM Conclusions

Based on the above-determined risk-free rate of 5.68%, MRP of 5.50%, beta of 0.55, and allowance for flotation costs of 0.50%, the Board concludes that a reasonable CAPM estimate for 2004 is 9.20%.

The Board will now consider the other ROE methodologies suggested by the parties to determine if the results, obtained from the application of such methodologies, warrant an adjustment to the Board's CAPM estimate of ROE.

4.2.4 Other Forms of the ERP Test

Dr. Booth gave equal weight to CAPM and to a multi-factor ERP model that indicated that a utility's equity risk premium over the long-Canada rate was a function of both the MRP and of the term spread of long-Canada rates over shorter-term rates. The midpoint of the results of Dr. Booth's multi-factor ERP model was approximately 7.5%,[48] which indicated an ROE of approximately 8.0% after including an allowance for flotation costs of 0.50%.

Dr. Booth's multi-factor ERP model would directionally support a reduction from the midpoint of the Board's CAPM range. However, the Board will only place limited weight on the results of Dr. Booth's multi-factor model for the following reasons:

1. The model has a low R-squared statistic, indicating low reliability of the model;
2. Today's interest rates are at the bottom edge of the range experienced over the study period; and

46 Decisions 2003-63, 2003-71, 2003-72 and 2003-100
47 CG Reply Argument, page 29
48 Exhibit 016-11(a), Evidence of L. D. Booth, pages 25-29

3. The adjustments that Dr. Booth indicated were required in developing the model.[49]

Dr. Vilbert (sponsored by NGTL) used both a CAPM model and an ECAPM model. His ECAPM model included an adjustment factor to compensate for an alleged tendency of CAPM models to under-estimate required returns for lower risk companies. Dr. Vilbert's ECAPM model resulted in a recommendation for an 11% ROE on a 40% common equity ratio. Dr. Vilbert's ECAPM results would directionally support an increase from the midpoint of the Board's CAPM range.

The Board notes Calgary/CAPP's argument that applying CAPM using long-term interest rates (long-Canada bond yields) in determining the risk-free rate, as was done by all experts in this Proceeding, already corrects for the alleged under-estimation that ECAPM was designed to address.[50] Calgary/CAPP argued that the under estimation would only be present if the CAPM were applied using short-term interest rates, which none of the experts did in this Proceeding.

The Board finds the Calgary/CAPP position persuasive and considers that the use of long-term Canada bond yields largely adjusts for the tendency of CAPM, when based on short-term interest rates, to under estimate the required returns for lower risk companies. Therefore, the Board will only place limited weight on the results of the ECAPM model.

Ms. McShane (sponsored by AltaGas/ATCO) used a DCF-based ERP test that resulted in a utility risk premium of 4.9%.[51] The Board notes that this implies a total utility ROE of 11.15%, after adding her recommended risk-free rate and the flotation cost. Ms. McShane also provided a realized historic utility ERP, based on Canadian and U.S. utility returns, which indicated a utility risk premium of 4.75%.[52] The Board notes that this implies a utility ROE of 11.0%.

Dr. Neri applied two ERP tests in addition to the CAPM, based on U.S. electric utilities and on U.S. gas distribution utilities, which produced utility equity risk premiums of 5.14 and 5.53%,[53] respectively. The Board notes that this implies a total utility ROE of 11.79% and 12.18%, respectively, after adding Dr. Neri's risk-free rate recommendation of 6.15% and a flotation allowance of 0.50%.

The Board notes that these utility return results of Ms. McShane's and Dr. Neri's other ERP tests are higher than many estimates of the market required return.

Ms. McShane's and Dr. Neri's other ERP tests would directionally support an increase from the midpoint of the Board's CAPM range. However, the Board shares CG's[54] and CAPP's[55] concern that it is not reasonable for the prospective required return on low risk firms to be close to or above the prospective overall market return.

49 Exhibit 016-11(a), Evidence of L. D. Booth, page 26
50 Calgary/CAPP Argument, page 12
51 Exhibit 005-10-2, Kathleen McShane, page 33
52 Ibid.
53 Exhibit 009-02(b), Schedules 6&7
54 CG Argument, page 49
55 CAPP Argument, page 17

On balance, the Board concludes that the results of the ERP tests other than CAPM would generally support a 2004 ROE above the Board's CAPM estimate, but that for the reasons set out above only limited weight should be placed on the results of the ERP tests other than CAPM.

4.2.5 Discounted Cash Flow Test

The Board notes from Table 2 that the Applicants' standard-method DCF estimates for ROE ranged from 10.3-14.1%. The Board notes ATCO's argument that any upward bias in analyst growth estimates may be less prevalent for stable industries including utilities. Nevertheless, the Board considers that there is merit in the intervener arguments[56] that the analysts' earnings forecasts used in the development of the DCF estimates have been biased high, resulting in DCF estimates that overstate the required return. The record of the Proceeding reveals no evidence on an appropriate discount to apply to the DCF test results to appropriately adjust for an overstatement in the required returns. Accordingly, the Board finds reliance on the Applicant's DCF estimates problematic.

The Board notes that Dr. Booth's DCF approach[57] was not based on an assessment of analysts' earnings forecasts, but was based on an assessment of the growth of the overall economy. Dr. Booth considered that the market as a whole would grow at the same rate as the nominal GDP growth rate of about 6%, which would indicate a total investor market return of 8.5% after including average dividends of 2.5% (which included an estimated 0.5% to account for share repurchases as surrogate dividends). Dr. Booth indicated that this was a geometric market return estimate and therefore under estimated the average short-run growth rate, since the arithmetic rate exceeds the geometric rate. Dr. Booth further indicated that his DCF analysis confirmed that an 8.12% allowed ROE for a regulated utility was fair and reasonable. However, the Board notes that Dr. Booth did not quantify the impact of converting from a geometric rate to an arithmetic rate, did not quantify, in this case, the impact of utilities having less risk than the market average, and did not add an allowance for flotation costs.

As a result of the above noted concerns, the Board concludes that no weight should be placed on the results of the DCF tests presented in this Proceeding.

4.2.6 Comparable Earnings Test

The Board notes that several Applicants indicated that the comparable investment test, envisioned in the court decisions referred to in Section 3 of this Decision, obligated the Board to place weight on the CE test.[58] However, in the Board's view, the CE test is not equivalent to the comparable investment test. The CE test measures **actual** earnings on **actual book value** of comparable companies, which, in the Board's view, does not measure the return "*it **would** receive if it **were** investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise*"[59] (emphasis added) (unless the securities were currently trading at book value). The Board notes that Cargill[60] expressed a similar view.

56 For example, Cargill Argument, page 23, and CG Argument, page 13
57 Exhibit 016-11(a), Evidence of L.D. Booth, page 36
58 ATCO Argument page 8, Companies Argument page 24
59 NUL, 1929, at 192-193
60 Cargill Argument, pages 6 and 7

The Board considers that the application of a market required return (i.e. required earnings on market value) to a book value rate base is appropriate in the context of regulated utilities.

The Board notes Ms. McShane's CE test result of "no less than 13%". The Board notes that this result is in excess of Ms. McShane's 11.75% estimate of the market return, excluding flotation allowance, incorporated in her CAPM result in Table 3. The Board also notes Dr. Booth's evidence that at no time in the last fourteen years has the average ROE of Corporate Canada exceeded 12.0%, and only twice in the last thirteen years has the average ROE been in double digits.[61]

In the Board's view, based on Dr. Booth's evidence regarding the achieved ROEs of Corporate Canada, and her own CAPM estimate, Ms. McShane's CE test result of "no less than 13%" exceeds a reasonable forecast of the prospective market required return. In the Board's view, CE test results for low risk companies, that exceed the forecast required return on the overall market, raise serious conceptual or methodological concerns regarding the relevance of the CE test. The Board does not consider it reasonable for the prospective required return on low risk firms to exceed the prospective overall market required return. The Board notes Ms. McShane's evidence that lower risk firms have outperformed the market over certain historical periods. However, in the Board's view, to forecast this result would not be credible.

The Board also notes that, in this Proceeding, various implementation problems with the CE test were discussed. These included sample selection problems, accounting differences, market power concerns, and problems matching the current business cycle stage. The Board recognizes that all traditional ROE tests suffer from methodological difficulties.

The Board concludes that it should place no weight on the CE test because of the implementation problems of the CE test and the above-noted conceptual and methodological concerns with the CE test.

4.2.7 Other Measures of Comparable Investment

Although the Board will not place any weight on the CE test, the Board considers that there may be other measures of comparable investment that should be considered in the establishment of an appropriate ROE. In this section, the Board will address other such measures of comparable investment that were raised in the Proceeding.

<u>Return Awards for Other Canadian Utilities</u>

The Board acknowledges the potential for circularity when considering awards by other regulators. Nevertheless, the Board considers that awards by other Canadian regulators may provide some indication of the appropriate ROE for the Applicants.

[61] Calgary/CAPP Argument, page 6

Dr. Evans provided, at the Board's request, a detailed compilation of ROE awards and other matters for Canadian utilities.[62] The following table is an excerpt from that compilation:

Table 5. Awarded ROEs for Other Canadian Utilities

	Date	Awarded ROE (%)
British Columbia		
Aquila Networks Canada (BC) Ltd.	November 2003	9.55
Pacific Northern Gas Ltd.	November 2003	9.90
Terasen Gas Inc.	November 2003	9.15
Ontario		
Enbridge Gas Distrbution	November 2003	9.69
Union Gas Ltd.	Jan. 1999/July 2001	9.95
Quebec		
Gaz Metropolitain	September 2002	9.89
Nova Scotia		
Nova Scotia Power Inc.	October 2002	10.15
Prince Edward Island		
Maritime Electric	October 2001	11.00
Newfoundland		
Newfoundland Power Inc.	June 2003	9.75
National Energy Board	November 2003	9.56

Directionally, the evidence on recent awards for other Canadian utilities would support a 2004 ROE above the Board's CAPM estimate. However, the Board concludes that limited weight should be placed on this evidence due to the potential for circularity.

Return Awards for U.S. Utilities

The Applicants generally took the view that it is appropriate to consider utility ROEs awarded by U.S. regulators, due to the similarity between Canadian and U.S. utilities and due to the high degree of integration of the capital markets of the two countries.

The Board notes the evidence of various Applicants that low risk gas distribution utilities in the U.S. have allowed returns in the 11% range on a 45% common equity component, and that prior to incentives, the base return for interstate electric transmission companies allowed by FERC is in excess of 12% on a 50% equity component.[63]

The Board also notes the submissions of various interveners that there are several differences between Canadian and U.S. regulation. The Board, in particular, notes CAPP's submission that U.S. pipelines operate under a regulatory regime that has exposed them to severe realized and potential risks. In this regard, the Board notes the evidence[64] of CAPP indicating low actual returns of a number of U.S. interstate pipelines.

[62] Exhibit 021-24
[63] ATCO Argument, pages 29-30
[64] Exhibit 015-11, Written Evidence of CAPP, pages 49-50

In the Board's view, the Applicants did not demonstrate that the regulatory regimes in the two countries are sufficiently comparable that the Board should place significant weight on the return awards for U.S. utilities. For example, the Board notes differences in legislation, public and regulatory policies, the higher prevalence of longer-term settlement arrangements, the federal/state jurisdictional divisions, the development of RTOs and other differences in the structure of regulated industrial sectors, and differences in national fiscal, tax and monetary policies. The Board notes AltaLink acknowledged that there are some differences in the Canadian and U.S. electric industry structures that may impact some of the higher return and equity component awards in the U.S.[65]

Furthermore, the Board notes the recent acquisitions, at premiums to book value, by U.S. companies of an interest in TransAlta Corporation's former distribution and transmission businesses. The Board considers these acquisitions, which are discussed further below, may be an indication that the regulated returns available in Alberta are not too low for U.S. firms, relative to investment opportunities in their home country given all relevant circumstances.

Directionally, the evidence on the awards available to U.S. utilities would support a 2004 ROE above the Board's CAPM estimate. However, the Board concludes that limited weight should be placed on this evidence due to the differences in the regulatory, fiscal, monetary, and tax regimes in the two countries.

FERC Incentives for Transmission Facilities

A number of the applicants suggested that if the Board did not reflect the incentive awards that FERC has in place for new electric transmission facilities, then capital might not be available for utility infrastructure in Alberta. These applicants argued that above-market ROEs would be in the public interest in order to ensure that sufficient capital is attracted for Alberta's infrastructure needs.

The Board is not persuaded that the existence of certain FERC-regulated transmission projects with allowed returns above the current market required rate of return would impair the ability of Alberta utilities to attract capital. In the Board's view, Alberta utilities do not compete for capital only with these projects, but rather with a broad universe of investment opportunities. Furthermore, if the higher allowed returns for these projects were material to the Canadian market required return, the Board considers that the impact of these higher allowed returns would already be reflected in the Canadian market required return.

Furthermore, the Board notes that the FERC incentives are intended to encourage RTO participation, independent ownership of transmission facilities, and investment in new facilities found appropriate pursuant to an RTO process. The Board notes that the objectives of encouraging RTO participation and encouraging independent ownership of transmission facilities are not applicable in Alberta. Similarly, the objective of encouraging investment in new independent transmission facilities into areas presently serviced by vertically integrated utilities is also not applicable in Alberta. Furthermore, the Board notes that both AltaLink and ATCO expressed continued strong interest in infrastructure development in Alberta.

The Board considers that there is no persuasive evidence in this Proceeding that demonstrates that above-market awarded returns are required to attract capital, and the Board notes that there

65 AltaLink Specific Reply Argument, third page

is no evidence of any Alberta TFO having any difficulty in attracting capital to date. The Board considers that to award such returns in the absence of need would unnecessarily and inappropriately result in additional costs to consumers.

Furthermore, the Board considers that if it were satisfied in some future application that it was appropriate to award incentive returns to attract capital in connection with the construction of certain new electric transmission facilities in Alberta, such returns would not be appropriate on existing facilities and may not be necessary in respect of all new infrastructure developments.

The Board is not persuaded that there is any requirement at this time to offer above-market ROEs or other incentives to attract capital for the construction of new electric transmission facilities in Alberta. The Board will not put any weight on the FERC incentives for transmission facilities, for the purposes of determining the generic ROE.

Alliance and Maritime and North East Pipelines (M&NP)
NGTL's view was that Alliance and M&NP are particularly relevant comparisons for NGTL. NGTL noted that both Alliance and M&NP are regulated and ship into markets served by gas that moves through NGTL and TransCanada Pipelines Ltd. (TCPL)'s Mainline. NGTL submitted that Alliance and M&NP, as the most recent large greenfield pipelines, show what returns are necessary to entice investment in regulated natural gas pipelines. Alliance has an ROE of 11.25% on 30% deemed equity and M&NP has an ROE of 13% on 25% deemed equity.

In regards to the regulated returns of Alliance and M&NP, the Board agrees with CAPP that these returns are not directly relevant, due to different circumstances (such as the level of ROE being locked in for a long period of time) and because they date back to a period of higher interest rates and returns. In this respect, the Board notes CAPP's argument that Alliance takes risks that NGTL does not, including some volume risk on an exception basis, long-term shipper contract default risk, and long-term interest rate risk,[66] and that the M&NP was built for a new untested basin with few pools having been delineated. In addition, the Board notes that the deemed equity ratios for Alliance and M&NP are lower than any Board-approved equity ratio, which would directionally reduce the impact on customer rates of a higher ROE.

Although, directionally, the absolute level of return for Alliance and M&NP would support a 2004 ROE above the Board's CAPM estimate, the Board concludes, based on the above analysis, that it should place limited weight on the Alliance and M&NP returns.

Market-to-Book Ratios and Acquisition Premiums
The Board notes the evidence, including that of AltaGas[67] and Calgary/CAPP[68] that the equity of utilities that earn a large portion of their earnings based on regulated formulas in other Canadian jurisdictions tends to trade at market-to-book ratios well above 1.0, albeit at premiums less than the average market premium.

The Board also notes that there have been a number of acquisitions of Alberta utilities in recent years, at prices that significantly exceeded book value. For example, in 2000, Aquila acquired TransAlta Corporation's distribution and retail businesses at a total price of 1.5 times book value. Book value was forecast to be $472 million at time of close, resulting in a forecast premium of

66 Exhibit 015-11 Written Evidence of CAPP, page 36 and 49
67 AltaGas Argument, page 24
68 Exhibit 016-11(b), Written Evidence of J.D. McCormick, page 5

$238 million.[69] Aquila subsequently sold TransAlta's former retail business to EPCOR Energy Services (Alberta) Inc. for $110 million, including a premium of $99 million.[70]

As well, in 2004, Fortis purchased Aquila for a premium of $215 million above the book value of $601 million.[71]

Similarly, with respect to the AltaLink acquisition of TransAlta Corporation's transmission assets, the Board notes Mr. McCormick's[72] evidence that a premium of $200 million was paid to acquire a rate base of approximately $644 million.

The Board agrees with the Applicants that there are a number of factors impacting market-to-book ratios of utility holding companies and that one has to be cautious making inferences regarding the regulated utilities. The Board also agrees that there may be strategic factors affecting the price that is paid to acquire a utility.

For example, NGTL submitted that its parent did not acquire a further interest in the Foothills pipeline, paying 1.6 times book value, for the opportunity to earn a return at the NEB formula rate; rather, the investment was made in an effort to increase the probability that TCPL will participate in a Northern pipeline project. The Board also recognizes that, in some cases, a premium might be paid for regulated assets in anticipation of significant future growth in rate base, to achieve geographic diversification or to obtain a foothold in a new market. However, parties are also aware of the constraints placed on regulated utilities with respect to affiliate transactions, particularly those with unregulated affiliates.

In the absence of such strategic factors, the Board would not expect a prudent investor to pay a significant premium unless the currently awarded returns are higher than that required by the market. The Board acknowledges the views of some parties that payment of a premium over book value for a regulated utility indicates that the recent ROE awards may have been higher than required by the market. The Board is not aware of the strategic factors that may have affected the price paid to acquire Alberta utilities in recent years. Nevertheless, the experience regarding the market-to-book values of utilities and the experience regarding the acquisition of Alberta utilities in recent years gives the Board some comfort that its recent ROE awards have not been too low.

Further in this regard, the Board notes AltaLink's testimony, in response to examination by the Chairman,[73] that AltaLink's decision to purchase TransAlta's transmission business considered Board awards for transmission entities of 9.75% ROE on a capital structure including 35% equity.

Directionally, the Board concludes that the experience regarding the market-to-book ratios of utilities and the experience regarding the acquisition of Alberta utilities in recent years is relevant and supports continuation of an ROE at or below the Board's CAPM estimate.

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69 Decision 2000-41, page 3
70 Decision 2000-71, page 3
71 Decision 2004-035, page 18
72 Exhibit 016-11(b) Evidence of J.D. McCormick, pages 39-40
73 Transcript, Volume 15, pages 2004-2006

Income Trusts

The Board notes the significant disagreement among parties with respect to return expectations of investors in Income Trusts. The Board notes that Mr. McCormick relied primarily on a sample of only five Income Trusts and that the validity of his sample selection was the subject of substantial debate.

In the Board's view, the theoretical return, indicated by Mr. McCormick, based on ROE does not address actual investor expectations on investment or actual historic returns on investment of Income Trust investors. For example, the Board notes that Income Trust prices often rose despite the fact that part of the distributions represented return of capital.

The Board generally agrees with the views of the Applicants that Income Trusts may be overvalued[74] due to investors' misperceptions and may be too new to be a reliable indication of required market returns. The Board also does not consider that there is any evidence that the allegedly lower return requirements for Income Trusts are achievable in a corporate structure. The Board notes that no party advocated that the Applicants be required to reconstitute as Income Trusts. The Board also notes that some Income Trusts have much higher equity ratios than the Applicants, which would directionally offset the impact of a lower ROE on customer rates.[75]

Nonetheless, the Board notes that Income Trusts are attracting a substantial amount of new capital.

Directionally, the Board considers that the experience with Income Trusts would support an ROE at or below the Board's CAPM estimate. However, for the reasons cited above, the Board concludes that limited weight should be placed on this experience.

Pension Return Expectations

Interveners generally took the position that TCPL's forecast pension return on Canadian equity investments of 9.5% was an indicator of the Canadian market return expected by TCPL. NGTL argued that the forecast of 9.5% was prepared by its actuaries and was not comparable to an investment hurdle rate. NGTL further argued that the forecast of 9.5% was a geometric estimate rather than an arithmetic estimate.

The Board acknowledges that forecast pension returns on equity investments may be conservative by their nature, but the Board nevertheless considers that forecast pension returns on equity investment are a valid indicator, albeit potentially conservative, of the forecaster's current market equity return expectation. However, the Board agrees with NGTL that the forecast pension return is akin to a geometric average and would therefore understate the forecaster's short-term expectation for the market return. Directionally offsetting this impact, the Board would expect the required return for utilities to be below the required overall equity market return.

On balance, the Board concludes that the evidence on forecast pension returns would support a modest increase from the Board's CAPM estimate.

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[74] NGTL Argument, page 105-107; ATCO Argument, page 43

[75] NGTL Argument, page 107

Other Investment Alternatives Available To Utility Shareholders

The Board notes NGTL's evidence that its parent, TCPL, has other investment alternatives, such as unregulated power generation projects, that earn a return higher than the return allowed for NGTL. NGTL also argued that TCPL has the option of making investments at higher returns in the U.S. and repatriating the profits to Canadians via the dividend tax credit. NGTL submitted that it requires a higher return in order to compete with these other investment opportunities of TCPL.

The Board agrees with the interveners[76] that NGTL's evidence regarding earnings on power generation projects were merely forecasts of earnings, and represented a limited and select sample. The Board also notes that NGTL did not supply any evidence that evaluated historical returns from other investments versus returns from its Canadian utility investments, which is one relevant factor to be considered when making prospective investment decisions.

The Board concludes that there is no basis on which to place any weight, other than already reflected in earlier tests, on other specific investment opportunities potentially available to utility investors or on stated expectations of return from such opportunities.

4.2.8 2004 ROE

The Board found above that a reasonable CAPM estimate for 2004 is 9.20%. The Board considers that it is appropriate to assess the results of other tests to determine if the 2004 ROE should be above or below the CAPM estimate.

The Board found above that the following evidence would generally support a 2004 ROE at or below the CAPM estimate:

1. Market-to-Book Ratios and Acquisition Premiums
2. Income Trusts

Similarly, the Board found above that the following evidence would generally support a 2004 ROE at or above the CAPM estimate:

1. ERP Tests Other Than CAPM
2. Return Awards for Other Canadian Utilities
3. Return Awards for U.S. Utilities
4. Alliance and M&NP
5. Pension Return Expectations

As discussed above, the Board did not put any weight on the following evidence in determining whether the 2004 ROE should be above or below the CAPM estimate:

1. Discounted Cash Flow Test
2. Comparable Earnings Test
3. FERC Incentives for Transmission Facilities
4. Other Investment Alternatives Available to Utility Shareholders

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[76] Cargill Argument page 22 and CAPP Argument page 23

In the next section of this Decision, the Board establishes an adjustment mechanism that includes an adjustment factor of less than 100% of the change in the long-Canada yield, which in the Board's view also supports a 2004 ROE above the CAPM estimate since the allowed ROE will not reflect a 100% adjustment factor, which is implicitly suggested by CAPM, and since a formulaic approach effectively creates a longer test period with respect to ROE.

In consideration of the impact of the above factors, it is the judgment of the Board that it would be appropriate to establish the 2004 ROE at a level that is 40 basis points above the Board's CAPM estimate. Therefore, the Board concludes the generic ROE for 2004 should be set at 9.60%.

4.3 Annual Adjustment Mechanism

As outlined earlier in this Decision, the Board will now address the potential use of an adjustment mechanism for ROE.

The following table summarizes the positions of the parties:

Table 6. Annual Adjustment Mechanism Recommendation by Parties

Party	Annual Adjustment Mechanism Recommendation
AltaGas/ATCO	50% of long-Canada bond yield change
Companies	75% of long-Canada bond yield change
ENMAX	100% of long-Canada bond yield change plus 100% of utility bond spread change
NGTL	Link to changes in Corporate bond yields
Calgary/CAPP	75% of long-Canada bond yield change
Cargill	75% of long-Canada bond yield change (80% or 100% also acceptable)
CG	75% of long-Canada bond yield change plus 50% of market dividend yield change
IPCAA	75% of long-Canada bond yield change

The Board notes that most parties favored an adjustment formula with the ROE changing by 75% of the change in the forecast long-Canada bond yield, provided that the Board accepted their starting positions on ROE.

The Board also notes Dr. Evan's evidence that a change based on 75% of the change in the long-Canada bond yield is driven by the differential tax rates between bonds and equity.[77]

The Board notes ATCO's and ENMAX's concern that it would be unfair to set an initial ROE based strictly on a CAPM analysis and to then allow only 75% of any increase in the long-Canada bond yield. In such a situation, ATCO and ENMAX favoured a 100% adjustment. The Board notes that in the previous section of this Decision, the Board established a generic ROE for 2004 of 9.60%, a level that is 40 basis points above the Board's CAPM estimate of 9.20%.

The Board does not consider that ENMAX's proposal to adjust the ROE by the sum of the change in the long-Canada bond yield and the change in the utility bond spread to be appropriate due to the difficulty of determining and tracking bond yields for a representative sample of corporate bonds.

[77] Companies Argument, page 89

The Board also does not consider CG's proposal to adjust the ROE by the sum of 75% of the change in the long-Canada bond yield and 50% of the change in the market dividend yield to be appropriate because of potential double-counting and because independent forecasts of dividend yields are not readily available in the same manner as the Consensus Forecast for debt.

The Board notes the Companies' proposal that the adjustment formula not commence until the year 2006. The Board notes that no other party proposed that implementation of an adjustment formula not commence until the year 2006. The Board does not consider that there is any reason to delay implementation of the adjustment formula until 2006.

Considering all of the above, the Board concludes that an adjustment to the generic ROE based on 75% of the change in long-Canada bond yield would be appropriate, beginning in 2005.

The Board considers the formula proposed by Dr. Evans (sponsored by the Companies) to be an appropriate method of implementing this adjustment:

$$ROE_t = 9.60\% + [0.75 \text{ x } (YLD_t - 5.68\%)]$$

where YLD_t = the forecast long-term Canada bond yield for year t.

Consistent with the approach used by the NEB, the forecast long-term Canada bond yield for year *t* shall be calculated as the average of the 3-month-out and 12-month-out forecasts of 10-year Canada yields as reported in the Consensus Forecasts[78] issue in November of the previous year, plus the average of the daily difference between the 10-year and the 30-year Canada bond yields for the month of October in the previous year, as reported in the National Post.

78 Consensus Forecasts Inc., London, England

4.4 Process to Review ROE

The following table summarizes the review process recommendations of the parties:

Table 7. Process to Review ROE – Recommendations by Parties

Party	Periodic Review	Other Review Triggers
AltaGas/ATCO	Review in 2007	• Long-Canada yield below 4% or above 8%. • A-rated utility bond spreads exceed 50% of the generic risk premium.
Companies	5 years	
ENMAX	Not more than 3 years	• Any Alberta utility is downgraded by a rating agency. • Formula result rises or falls more than 200 basis points from initial level.
NGTL	2 years	
Calgary/CAPP	5 years	• Long-Canada bond yield changes by more than 3.0%.
Cargill	3 to 5 years	
CG	3 years for the first review; 5 years thereafter	• Material change in investment risk of the regulated sector. • Material change in the market equity risk premium.
IPCAA	5 years	
IPPSA	5 years	

In the Board's view, it would be appropriate to trigger a review of whether the adjustment mechanism continues to yield a fair ROE, if there is a material change in the forecast long-Canada bond yield from the November 2003 forecast.

The Board considers that the most straightforward method of implementing this trigger is by placing bounds on the range of ROEs that can be established pursuant to the adjustment mechanism.

In this regard, the Board considers ENMAX's proposed change of 200 basis points in the generic ROE to be a reasonable trigger. The Board notes that a change of 200 basis points in the generic ROE is equivalent to a change of 267 basis points in the long-Canada bond yield, which is effectively higher than the long-Canada bond yield trigger proposed by ATCO but lower than the long-Canada bond yield trigger proposed by Calgary/CAPP.

Therefore, if the ROE resulting from the adjustment mechanism results in an ROE of less than 7.6% or greater than 11.6%, the Board will seek the views of parties on whether the adjustment mechanism continues to yield a fair ROE in the manner described below.

The Board considers that ATCO's proposed trigger of A-rated utility bond spreads exceeding 50% of the generic risk premium would be difficult and contentious to implement, principally due to controversy in the choice of the sample of utility bonds.

The Board does not consider ENMAX's proposed automatic trigger of any Alberta utility downgraded by a rating company to be appropriate because of the many factors and judgments that may contribute to a downgrade for an individual company, including their unregulated business results.

The Board considers that CG's proposed triggers of a material change in the investment risk of the regulated sector or a material change in the market risk premium would be difficult and contentious to implement. The Board considers that material changes in investment risk of the regulated sector or in the market risk premium can be addressed at the time of the periodic review.

The Board notes that all parties agreed that a review of whether the adjustment mechanism continues to yield a fair ROE should be conducted after a defined period of time. The Board notes that the time period for a review suggested by the parties varied from 2-5 years.

The Board considers that a review period of 5 years would appropriately balance the desire to achieve regulatory efficiencies through the use of an adjustment mechanism and the need to ensure that the ROE adjustment process continues to result in an appropriate ROE.

In the Board's view, triggering an early consideration on whether or not to conduct a review if the ROE resulting from the adjustment mechanism is less than 7.6% or greater than 11.6% also supports the selection of a five year review period.

The Board notes the Companies' proposal of a *de novo* review of all cost of capital matters at the end of five years. However, the Board does not consider that it would be appropriate to automatically trigger a *de novo* review either in the event that the adjustment mechanism results in a ROE of less than 7.6% or greater than 11.6% or at the end of five years, without first assessing whether the adjustment mechanism continues to yield an appropriate ROE result.

Therefore, the Board will first seek the views of parties on the preliminary question of whether the adjustment mechanism continues to yield a fair ROE prior to the establishment of the common ROE for the year 2009, or earlier if the ROE resulting from the adjustment mechanism for years prior to 2009 is less than 7.6% or greater than 11.6%. The Board will consider the views of parties on this preliminary question before deciding whether to undertake a general review of ROE or of the adjustment mechanism.

The Board notes that any party, at any time, will be free to petition the Board to consider a review of the adjustment formula, or to exempt a particular party from its application. The Board agrees with the submissions of the Companies,[79] Calgary/CAPP,[80] and IPCAA[81] that there would be an element of judgment involved in determining whether circumstances have changed sufficiently to warrant review, and that the ROE and adjustment mechanism determined by the Board should be entitled to a presumption of reasonableness, with any party seeking early review or an exemption bearing the onus of demonstrating that circumstances have rendered them unreasonable. The petitioning party would bear the onus of demonstrating a material change in facts or circumstances from the evidence filed in this Proceeding to merit a review of the adjustment formula or an exclusion from the formula.

79 Companies Argument, page 92
80 Calgary/CAPP Argument, pages 23 and 64 (the later regarding capital structure)
81 IPCAA Argument, page 24

5 CAPITAL STRUCTURE

5.1 Introduction

The Board notes that the capital structures determined in this Proceeding are premised on the business risks that existed at the time of the Proceeding.

For the convenience of readers, the following table (ordered by sector) compares the equity ratios that were last approved by the Board with the equity ratios recommended by the Applicants, CG and Calgary/CAPP:

Table 8. Recommended Equity Ratios vs. Last Board Approved Equity Ratios

	Last Board-Approved (%)	Recommended by Applicant (%)	Recommended by CG (%)	Recommended by Calgary/CAPP (%)
Electric and Gas Transmission				
ATCO Electric TFO	32.0	38.0	30.0	30.0
AltaLink	34.0[4]	37.5	30.0	32.0
EPCOR TFO	35.0	40.0	30.0	35.0
NGTL	32.0	40.0	32.0	33.0
ATCO Pipelines	43.5	50.0[3]	40.0	38.0
Electric and Gas Distribution				
Aquila	N/A [1]	42.5	35.0	35.0
ATCO Electric DISCO	35.0	45.0[2] (+ 5-10 %)	35.0	35.0
ENMAX DISCO	N/A [5]	50.0	35.0	40.0
EPCOR DISCO	N/A [5]	45.0	35.0	40.0
ATCO Gas	37.0	40.0	37.0	35.0
AltaGas	41.0	45.0	40.0	35.0

1 The Board did not specifically approve this ratio; it was part of a negotiated settlement approved in Decision 2003-019, which included a deemed 40% equity ratio as one of many settled parameters of the revenue requirement.
2 ATCO Electric DISCO requested a further increase of 5-10%, beyond its original request of 45%, in its equity ratio to account for ATCO's perception of additional business risks resulting from the *RDS Amendment Regulation.*[82]
3 ATCO Pipelines, in addition to a 50.0% equity ratio, also proposed a 0.5% addition to ROE.
4 In Decision 2003-061, the Board approved an equity ratio for AltaLink of 32%, plus an additional 2% to offset the impact on the interest coverage ratio of a partial allowance of income taxes in the revenue requirement.
5 ENMAX and EPCOR Distribution were subject to Board jurisdiction effective January 1, 2004.

The Board notes that, with the exception of CGA, the interveners who did not sponsor expert evidence generally supported the views of CG and Calgary/CAPP in argument. The Board also notes that the Applicants did not generally take a position on the appropriate capital structures for other Applicants.

In the Board's view, setting an appropriate equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk.

82 *Regulated Default Supply Amendment Regulation* (AR 323/2003)

To determine the appropriate equity ratio for each Applicant, the Board will consider the evidence and, where applicable, the experts' views and rationales in each of the following topic areas:

1. The business risk of each utility sector and Applicant;
2. The Board's last-approved equity ratio for each Applicant (where applicable);
3. Comparable awards by regulators in other jurisdictions;
4. Interest coverage ratio analysis; and
5. Bond rating analysis.

The Board notes the general consensus that the electric and gas transmission sectors had the least risk of all Applicants in this Proceeding. Further, the Board notes that no party argued otherwise.

The Board will first consider the appropriate capital structures for the electric and gas transmission Applicants, and the Board will subsequently consider the appropriate capital structures for the electric and gas distribution Applicants.

5.2 Electric and Gas Transmission

The Board notes from the above Table 8 that for the taxable electric transmission companies,[83] the Applicants proposed equity ratios of 37.5 and 38.0%, whereas the interveners proposed an equity ratio of 30.0%.

With respect to transmission companies that are not fully taxable, the Board will provide its findings later in this Decision.

With respect to gas transmission, NGTL proposed an equity ratio of 40%, while the interveners proposed 32 and 33%. The equity ratios proposed by all submitting parties for ATCO Pipelines were materially higher than the equity ratios each proposed for NGTL. The Board will address ATCO Pipelines later in this Decision.

Business Risk

The Board notes that the Companies[84] compared the risks of electric transmission companies with the risks of NGTL as they existed in 1995. Dr. Evans (sponsored by the Companies) considered that electric transmission companies have more risk today than NGTL had at the time NGTL's equity ratio was last approved, for 1995.[85]

However, the Board considers that because it now has evidence regarding all Applicants' current risks, the utilities should be compared based on the business risks that existed at the time of this Proceeding. This was the approach of the experts other than Dr. Evans.

ATCO submitted that electric transmission companies were more risky than NGTL, principally due to the smaller size of the electric transmission companies relative to NGTL, the higher expected growth rates of the electric transmission companies relative to NGTL, and ATCO's

83 In this Proceeding, AltaLink assumed it was fully taxable, but the Board did not.
84 Companies Argument, page 96
85 Companies Argument, page 98

perception of a greater degree of regulatory uncertainty for the electric transmission companies relative to NGTL.

Although NGTL did not compare its level of business risk to that of other utilities, it did submit extensive evidence with respect to its own business risks, including operating expense risk, supply risk, competition risk, volume risk and credit risk.

Calgary/CAPP[86] and CG[87] each considered NGTL to have higher short and long-term business risk than the electric transmission companies, because NGTL faces operating expense risk, supply risk, competition risk, volume risk and credit risk, whereas the electric transmission companies only face operating expense risk. The interveners[88] viewed TFO growth prospects as an opportunity rather than a risk.

The Board agrees with the interveners that NGTL has a higher short-term business risk than the electric transmission companies, principally due to higher competition and credit risks. The Board also considers that NGTL potentially faces higher long-term risks due to supply risk although, in the Board's view, the bulk of that risk, if it materializes, will likely be identified early enough for NGTL to apply to the Board for potential adjustments to throughput forecasts and/or depreciation rates.

The Board also notes that NGTL does not have the same revenue certainty, as do the electric transmission companies. The Board also considers the higher expected growth rates of the electric transmission companies to be an opportunity for the TFO shareholders to increase their investments, and not fundamentally a matter of increased risk. The Board notes that utilities are allowed a return on funds used during construction. In addition, the Board was not persuaded that electric transmission companies have a greater degree of regulatory uncertainty than gas transmission companies.

The electric transmission companies have a single customer, the AESO. The Board considers the AESO to be of minimal credit risk. Further, the Board notes that the AESO pays the electric transmission companies 1/12 of their approved revenue requirement on a monthly basis with no adjustment for changes in demand or supply of electricity carried by the TFO.

For all of the above reasons, the Board does not agree with ATCO and the Companies that the electric transmission companies are more risky than NGTL.

The Board concludes that taxable electric transmission companies have the lowest business risk of any utility sector regulated by the Board, and that the risks of NGTL are somewhat higher than the risks of a fully taxable electric TFO.

The Board notes, from the above Table 8, that CG's and Calgary/CAPP's recommended equity ratios for NGTL were 2% and 3%, respectively, higher than their recommended equity ratio for a fully-taxable electric TFO. The Board also notes that NGTL did not provide the Board with an indication of its views respecting its risks relative to electric transmission companies, and, more particularly, did not indicate a view on an appropriate equity ratio differential compared to electric transmission companies.

86 CAPP/Calgary Argument, page 56
87 CG Argument, pages 67-70
88 CG Argument, page 70; Calgary/CAPP Argument, pages 67-70

The Board considers that business risk, in isolation, would indicate an equity ratio for NGTL that is 2-3 % higher than the equity ratio for a fully taxable TFO.

Comparison to Previous Board Awards

The Board notes that the last Board-approved equity ratio for NGTL of 32% was established for 1995.[89] The Board agrees with the general view of the experts that the business risks of NGTL have increased since 1995, principally due to a potentially higher supply risk and a higher competition risk.

Directionally, the Board concludes that NGTL's higher business risk, in isolation, supports an equity ratio for NGTL higher than 32%.

In Decision U99099, the Board established an equity ratio for electric transmission companies (TFOs) of 35%. In Dr. Evan's view,[90] the risks of electric TFOs have not changed since the time of Decision U99099, which would indicate that no change in equity ratio was appropriate. However, the Board considers that the risks of electric transmission companies have likely decreased since the time of Decision U99099 due to increased clarity of the role of the TFO, increased clarity with respect to the AESO's role and structure, the resolution of liability issues and the changes in transmission policy including the role of competitive bidding.

Directionally, the Board considers that this factor, in isolation, supports an equity ratio for fully taxable electric transmission companies lower than the 35% determined in Decision U99099.

The Board notes the last approved equity ratio for ATCO Electric TFO was 32% and for AltaLink was 34% (32% + 2% for the interest coverage ratio adjustment). However, these ratios were established when NGTL's award was 32%.

Directionally, the Board considers that this factor, in isolation, supports an equity ratio for fully taxable electric transmission companies similar to the last award of 32% or marginally higher.

Comparable Awards by Regulators in Other Jurisdictions

The Board acknowledges the potential for circularity when considering awards by other regulators. The Board also recognizes that business risks may be quite different in other jurisdictions. The Board has discussed some of these differences in the ROE section of this Decision and will provide further comment in following sections of this Decision. Nevertheless, the Board considers that comparable awards by other regulators may provide some indication of the appropriate capital structures for the Applicants.

As a result of the electric industry restructuring in Alberta, the Board notes that there are no TFO entities in the other provinces of Canada that are directly comparable to TFO entities in Alberta. However, in the Board's view, Canadian federally regulated natural gas transmission pipelines are of some assistance in drawing comparisons to both NGTL and the taxable electric transmission companies.

[89] U96001, Nova Gas Transmission Ltd., 1995 General Rate Application, Phase 1

[90] Companies Argument, page 110

The Board considers that the nature of NGTL as a gathering system, with numerous receipt and delivery points, a diverse customer base, and other related factors demonstrates an additional degree of business risk for NGTL when compared to the TCPL Mainline. However, the breadth of NGTL's diverse customer base mitigates the additional risk to a large degree, since the loss of any one customer or point of supply would likely not be material to the long-term risks faced by NGTL. The Board notes that in RH-4-2001, dated June 2002, the NEB awarded TCPL's Mainline a 33% common equity ratio based on its conclusion that "the level of business risk facing the Mainline has increased since 1995…".[91] The NEB cited "increases in the risks resulting from pipe-on-pipe competition and increased supply risk but noted, "other sources of risk have not changed materially".[92]

The Board notes that NGTL's last awarded equity ratio of 32% for 1995 was 2% higher than the contemporaneous NEB award of 30% for TCPL's Mainline. The Board notes that the same 2% differential if applied today would result in an equity ratio of 35% for NGTL. The Board considers that this factor, in isolation, supports an equity ratio of 35% for NGTL.

Since the Board considers electric transmission companies to have less risk than NGTL, the Board considers that this factor, in isolation, supports an equity ratio of less than 35% for taxable electric transmission companies.

The Board notes Dr. Evan's evidence,[93] provided at the Board's request, that the awarded equity ratios for the Foothills, ANG and TQM pipelines remain at the 30% level that the NEB established in 1995.

However, the Board notes the NEB's view[94] that Foothills and ANG operated on a lower risk monthly cost of service basis, and that TQM had a high degree of assurance that its costs would be recovered. For these reasons, the Board considers the risks of the taxable electric transmission companies and NGTL are somewhat higher than the risks of Foothills, ANG and TQM. Consequently, the Board considers that this factor, in isolation, supports an equity ratio of more than 30% for both the taxable electric transmission companies and NGTL.

The Board notes that the awarded equity ratio of the Westcoast Energy pipeline remains at 35%, which was set by the NEB in 1995. The Board also notes the NEB's view[95] that Westcoast had higher risks due to the nature of its gathering system and processing plants and due to the hydrogen sulfide content of the gas it transports. For these reasons, the Board considers the risks of taxable electric transmission companies to be lower than the risks of Westcoast and the Board considers the risks of a large gathering system like NGTL to be more similar to Westcoast than to the electric transmission companies. Consequently, the Board considers that this factor, in isolation, supports an equity ratio of approximately 35% for NGTL and less than 35% for the taxable electric transmission companies. However, the Board would note that there are also differences between Westcoast and NGTL.

[91] RH-4-2001, page 58
[92] RH-4-2001, page 28
[93] Exhibit 021-24
[94] RH-2-94, page 26
[95] RH-2-94, page 25

Interest Coverage Ratio Analysis

The Board notes that S&P provides guideline interest coverage ratios,[96] corresponding to various corporate credit ratings, for utilities of various business risk profiles (risk ranking levels). The Board further notes ATCO's evidence[97] that the estimated S&P risk ranking for ATCO Electric transmission is "2" and that the actual S&P business risk profile ranking for NGTL is "3".

The S&P guidelines indicate that for a utility with a risk ranking of "2", a pretax interest coverage ratio in the range of 2.3 to 2.9 times is indicated for an "A" debt rating.

The Board notes that S&P does not rigorously apply its guidelines with respect to each specific financial ratio. In addition to interest coverage ratios, S&P reviews a number of other key financial ratios, as well as many diverse and often subjective factors, in order to arrive at a specific credit rating for an individual utility.

The Board notes that Enbridge Gas has been assigned a risk ranking of "2", which would imply that electric and gas transmission companies, which are less risky, could be considered to be ranked at less than "2".

The Board does not have a target credit rating for utilities under its jurisdiction. The Board is of the view, however, based on the evidence before it in this Proceeding, that interest coverage ratios and credit ratings are important considerations in assessing the appropriate capital structure. However, the Board considers that the foregoing are just one set of factors to consider.

The Board notes that DBRS has indicated, in its NGTL credit rating report,[98] that an interest coverage ratio "above 2 times … is acceptable for a regulated cost of service-based business".[99] The Board notes that the DBRS report, "Methodologies in Rating Utilities", dated June 2002,[100] indicates a fixed-charge coverage ratio of 1.5 for a DBRS debt rating from BBB to A. The report's definition of fixed-charge coverage, in cases where preferred shares do not exist, is the same as the definition of interest coverage that the Board has used throughout this Decision. The Board notes the apparent inconsistency in the two statements, but considers that taken together, a conclusion can be drawn that an interest coverage ratio near 2 times might be appropriate for low risk regulated entities. The Board also notes Dr. Booth's (sponsored by Calgary/CAPP) evidence that an interest coverage ratio of 2.15 times is reasonable for pipelines, considering their historic actual levels.[101]

The Board notes that some parties have expressed a concern that the acceptable equity ratios for regulated utilities in Alberta could potentially be overstated,[102] if the S&P guidelines with respect to interest coverage ratios were applied in a mechanical manner without consideration of other factors.

96 Exhibit 008-02, pre-filed Information Response AUMA-AP-11
97 Exhibit 005-11-1, Capital Structures for the ATCO Utilities, Kathleen McShane, pages 9-11
98 Exhibit 013-17, DBRS credit rating report on NGTL, dated June 26, 2002, page 1
99 Exhibit 013-17, page 9 of 35
100 Exhibit 008-02, pre-filed Information Response CAL-AP-8
101 Exhibit 016-11(a), Evidence of L.D. Booth, page 63
102 Calgary/CAPP Argument, page 28

The Board has calculated the pretax interest coverage ratios that would result for a utility, with no preferred shares, using a 2004 tax rate of 33.87%,[103] using the ROE that the Board determined in this Decision of 9.6%, and applying a range of equity ratios and embedded debt costs. The Board will use the following table as one of several tests to evaluate and determine the appropriate common equity ratios.

The interest coverage ratio results for a range of equity ratios and embedded debt costs are as follows:

Table 9. Pretax Interest Coverage Ratios at Varying Embedded Debt Costs

Equity	Embedded Debt Cost					
Ratio	6.0%	6.5%	7.0%	7.5%	8.0%	8.5%
30.0%	2.0	2.0	1.9	1.8	1.8	1.7
31.0%	2.1	2.0	1.9	1.9	1.8	1.8
32.0%	2.1	2.1	2.0	1.9	1.9	1.8
33.0%	2.2	2.1	2.0	2.0	1.9	1.8
34.0%	2.3	2.2	2.1	2.0	1.9	1.9
35.0%	2.3	2.2	2.1	2.0	2.0	1.9
36.0%	2.4	2.3	2.2	2.1	2.0	2.0
37.0%	2.4	2.3	2.2	2.1	2.1	2.0
38.0%	2.5	2.4	2.3	2.2	2.1	2.0
39.0%	2.6	2.4	2.3	2.2	2.2	2.1
40.0%	2.6	2.5	2.4	2.3	2.2	2.1
41.0%	2.7	2.6	2.4	2.3	2.3	2.2
42.0%	2.8	2.6	2.5	2.4	2.3	2.2
43.0%	2.8	2.7	2.6	2.5	2.4	2.3
44.0%	2.9	2.7	2.6	2.5	2.4	2.3
45.0%	3.0	2.8	2.7	2.6	2.5	2.4

The above table shows the results of the mathematical calculations. The Board understands that bond ratings do not rely solely on precise mathematical results. Bond ratings incorporate a variety of factors, including the use of judgment.

The Board cautions readers not to interpret the level of precision expressed in the above table to be absolute in arriving at the appropriate equity ratio.

The Board is aware that some companies have higher embedded debt costs but these embedded debt costs are expected to decline as older, higher-cost debt is retired. The Board also notes that the embedded debt cost for AltaLink is lower than 6%, but that this embedded cost of debt could be understated since AltaLink's long-term financing does not appear to be fully in place.

The Board did not use the above table in a precise mathematical manner. Rather, the Board evaluates the data in the table above by looking at ranges, various company situations, longer-term effects, impacts of declining embedded costs, stability of capital structure awards as embedded debt costs change, and the consideration of other factors that are discussed in this Decision.

[103] 21% Federal rate, 1.12% surtax and 11.75% provincial tax (12.5% through March 31, 11.5% thereafter)

The Board further considers that all of these differing ratios are merely indicators in arriving at a level of coverage that is considered comfortable and acceptable.

Accordingly, based on the evidence and the above discussion, the Board concludes that an acceptable pretax interest coverage ratio for electric and gas transmission companies, in isolation, is near 2 times.

The Board considers that interest coverage ratio analysis, in isolation, supports equity ratios for taxable electric transmission companies and gas transmission companies greater than the currently approved equity ratios of 32% for ATCO Electric and NGTL.

The Board considers gas transmission companies to have slightly more risk than electric transmission companies and, therefore, the Board considers that this factor, in isolation, indicates that gas transmission companies should have slightly more equity than electric transmission companies.

Bond Rating Analysis

As noted above, the Board does not have a target credit rating for utilities under its jurisdiction. Further, the Board has discussed bond ratings, earlier in this Decision, in the context of the interest coverage ratios. Bond ratings are another factor in determining an appropriate capital structure.

With respect to the indications provided by actual bond ratings, Dr. Evans provided, at the Board's request, a detailed compilation of comparable equity ratios and bond ratings. The following table is an excerpt from that compilation, showing the awarded and the adjusted actual equity ratios for each utility regulated by the Board that has its own bond rating:

Table 10. Equity Ratios and Bond Ratings

	Last Board Awarded Equity (%)	Adjusted Actual Equity[104] (%)	DBRS credit rating[105] and deemed equity ratio at the same date (%)		S&P credit ranking and common equity ratio at the same date (%)	
AltaLink L.P.	34	38.3	A (high)	34.0[106]	A-	35 – 40 implied[107]
EPCOR Transmission	35	37	BBB (high)[108]	35.7[109]		
NGTL	32.2+0.3 preferred	40.3	A	38.9[110]	A-	36.0[111]
Aquila	40 (settlement)	41.9	A (low)	45.5 / 40.0[112]		

104 Exhibit 021-24 Dr. Evans calculated the most recently available Adjusted Actual Equity by treating short-term debt as debt, and by treating preferred shares and subordinated debt as 80% equity, consistent with the treatment described at page 106 of Decision 2003-061.

105 Source: Dr. Evans, Exhibit 021-24

106 Exhibit 021-45, AltaLink DBRS credit report, dated September 26, 2004, page 6

107 Exhibit 003-02-6, AltaLink S&P credit report dated May 16, 2003, page 4, indicates expected allowed equity of 35% and actual debt at 60-65% (implies actual equity of 35 to 40%).

108 Exhibit 012-03-h, DBRS letter regarding EPCOR Transmission Inc.'s indicative bond rating dated June 19, 2002

109 Exhibit 012-03-b, EPCOR Transmission Inc. Cost of Capital

110 Exhibit 021-43(c), beginning page 21 of 52, DBRS report on NGTL dated October 17, 2003, page 5

111 Exhibit 013-17, page 23 of 25, S&P report on NGTL dated June 19, 2003, page 3

Regarding EPCOR Transmission, the Board notes that the DBRS rating in the above table was only an indicative DBRS rating of BBB (high)[113] if DBRS had rated EPCOR in 2002, assuming no debt guarantee from the parent. The DBRS rating indication did not show the equity ratio used. However, the Board notes that an equity level of 35.7% for EPCOR Transmission was applicable[114] at the time that DBRS determined their bond rating to be BBB (high). The Board notes that the cost of debt has been declining since 2002[115] and as a result, the bond rating for a given equity ratio should improve as debt reaches maturity and is replaced. Consequently, the Board considers that this factor, in isolation, indicates that the equity ratio for EPCOR Transmission should be approximately 36%.

From the above table, the Board notes that AltaLink had DBRS and S&P credit ratings of A (high) and A- based on an equity ratio of 34% and a projected equity ratio of 35 to 40%, respectively. Furthermore, the Board notes that AltaLink has a substantial amount of goodwill on its books,[116] amounting to approximately 19% of its assets, which would require incremental equity support, compared to a TFO without goodwill. Consequently, the Board considers that this factor, in isolation, supports an equity ratio for AltaLink, based on rate base, somewhat below 34%.

The Board notes that NGTL has DBRS and S&P credit ratings of A and A- based on equity ratios of 38.9 and 36.0% respectively. In addition, the Board notes that the DBRS credit rating[117] of NGTL is partly based on its parent, TCPL. However, the Board notes that the S&P report[118] indicates that the credit rating is effectively that of TCPL, rather than that of NGTL itself. Therefore, in the Board's view, the adjusted actual equity ratio of NGTL may not be indicative of its required equity ratio, on a standalone basis.

Conclusion

At the beginning of this section, the Board indicated that it would consider a variety of factors for the electric and gas transmission companies.

As discussed in the preceding sections, in the Board's view, setting an appropriate equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk.

The following table summarizes the indicated equity ratios that arise from various factors as discussed in the earlier sections.

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112 Exhibit 004-12, DBRS Report on Aquila, page 5, indicating 54.5% net debt at March 31, 2002 (implies 45.5% equity), and indicating 40.0% deemed equity at December 31, 2001

113 Exhibit 012-03-h, DBRS letter regarding EPCOR Transmission Inc.'s indicative bond rating dated June 19, 2002

114 Exhibit 012-03

115 Ibid.

116 Exhibit 021-45, AltaLink DBRS credit report, dated September 26, 2004, page 6

117 Exhibit 021-43(c), page 21 of 52, DBRS report on NGTL dated October 17, 2003, page 1

118 Exhibit 013-17, page 23 of 25, S&P report on NGTL dated June 19, 2003, page 1

Table 11. Indicated Common Equity Ratios for Transmission Companies By Factor

Factor	Indicated Electric Transmission	Indicated Gas Transmission
Business Risk	Lowest	TFO + 2-3%
Previous Board Awards	≥32%, <35%	>32%
Awards in Other Jurisdictions	>30%, <35%	~35%
Interest Coverage Ratio Analysis	>32%	>32%, >TFOs
Bond Rating Analysis	EPCOR ~36% AltaLink <34%	May not be indicative

After considering all of the above factors and after applying its judgment, the Board concludes that an appropriate common equity ratio for fully taxable electric transmission companies, with no preferred shares, is 33.0% and that an appropriate common equity ratio for gas transmission companies is 35.0%.

The Board will now consider each electric and gas transmission Applicant, individually.

5.2.1 ATCO Electric Transmission

The Board considers that ATCO Electric Transmission does not have any material differences in business risk from the typical TFO.

The Board also notes that ATCO Electric Transmission has preferred shares in its capital structure. Although the preferred shares provide additional support to the capital structure, in this analysis, the Board has evaluated the appropriate common equity ratio as if the company had no support from its preferred shares.

For the same reasons that were provided above, the Board concludes that an appropriate common equity ratio for ATCO Electric Transmission, a fully taxable TFO, is 33.0%.

The Board will further address the issue of ATCO's preferred shares later in this Decision.

5.2.2 EPCOR Transmission

The Board considers that EPCOR Transmission does not have any material differences in business risk from the typical TFO.

The Board therefore considers that any difference between the equity ratio for a fully-taxable electric TFO with no preferred shares and the equity ratio for EPCOR Transmission should only reflect the fact that EPCOR Transmission does not have any allowance for income taxes in its approved revenue requirement.

Dr. Evans (sponsored by the Companies, including EPCOR Transmission) recommended that non-taxable utilities be allowed an extra 2.5% equity. Dr. Evans argued that this additional equity component was warranted due to the generally lower interest coverage ratios and the greater variability of net income for non-taxable utilities.[119]

[119] Companies Argument, page 94

For similar reasons, Calgary/CAPP recommended that non-taxable entities be allowed an extra 5% equity.[120]

ENMAX argued[121] that its non-taxable status justified an additional 8% equity, based on the precedent established by the Board for AltaLink in Decision 2003-061.

All other parties who took a position, on the issue of non-taxable utilities, were of the view that no allowance for additional equity should be provided for non-taxable entities, principally due to a perceived offsetting benefit of lower, more competitive rates. ATCO argued that such an increment to the equity ratio would provide an inappropriate competitive advantage to non-taxable entities.

The Board agrees that a non-taxable entity has a higher volatility of earnings than an otherwise equivalent taxable company, arising from the lack of an income tax component in its forecast revenue requirement. The Board notes that there was no disagreement that the absence of taxation, while lowering costs, increases the volatility of earnings.

In the Board's view, arguments regarding the competitive advantage of non-taxable entities do not have persuasive merit in the context of regulated electric utilities, which do not compete with each other.

However, the Board is not persuaded that the higher volatility of earnings warrants an increase in the equity ratio as high as recommended above. The Board considers that an extra 2% equity would appropriately account for the higher business risks and earnings volatility of a non-taxable entity.

Adding the 2% increment to the 33% equity ratio determined above for a fully taxable TFO, the Board concludes that an appropriate common equity ratio for EPCOR Transmission is 35.0%.

5.2.3 AltaLink

The Board considers that AltaLink does not have any material differences in business risk from the typical TFO.

The Board therefore considers that any difference between the equity ratio for a fully-taxable TFO with no preferred shares and the equity ratio for AltaLink should only reflect the differences in the amount of income taxes included in the respective revenue requirements.

The Board notes that in Decision 2003-061, the Board allowed an additional 2% on the equity ratio to recognize the disallowance of 25% of the requested income taxes, bringing the total common equity component to 34%. The additional 2% equity was intended to maintain the same interest coverage ratio as if there had been no disallowance of income taxes. The Board recognizes that a review and variance application with respect to Decision 2003-061 is pending.

The Board notes the adjustment to AltaLink's equity ratio was intended to maintain the same interest coverage ratio as if there had been no disallowance of income taxes, whereas the purpose of the adjustment to the equity ratios of the municipally owned utilities in this Decision is to

120 Calgary/CAPP Argument, page 59-60
121 ENMAX Argument, page 36

appropriately account for their higher volatility of earnings. The Board considers these two situations to be fundamentally different.

The Board notes that no party addressed the appropriate adjustment to AltaLink's equity ratio to reflect the partial disallowance of income tax. Assuming that the Board's disallowance of 25% of the requested income taxes is continued, the Board considers that it would continue to be appropriate to adjust AltaLink's equity ratio to maintain the same interest coverage as if there had been no disallowance of income taxes.

Adding the 2% adjustment to the 33% equity ratio determined above for a fully taxable TFO, the Board concludes that an appropriate common equity ratio for AltaLink is 35.0%.

If AltaLink were to have a full income tax allowance included in its approved revenue requirement, the Board considers that the appropriate common equity ratio for AltaLink would then be 33.0%.

5.2.4 NGTL

For the same reasons that were provided above, the Board concludes that an appropriate common equity ratio for NGTL, a gas transmission company, is 35.0%.

5.2.5 ATCO Pipelines

The Board notes that no party took the position that ATCO Pipelines has the same or lower business risk as NGTL, the other gas transmission Applicant. From Table 8, the Board notes that Calgary/CAPP considered ATCO Pipelines to be the highest risk investor owned utility, and that CG considered ATCO Pipelines to be tied with AltaGas as the highest risk utility.

Accordingly, in this section, the Board will assess the appropriate equity ratio for ATCO Pipelines and its differences from the typical gas transmission company. In this regard, the Board will draw on its previous analysis and discussion earlier in this section. Further, the Board will address the additional information applicable to ATCO Pipelines.

The Board notes the general consensus that ATCO Pipelines has higher competition risk than NGTL. Several parties suggested that resolution of outstanding gas pipeline competition issues could result in a reduction to the competition risk faced by ATCO Pipelines. The Board notes that at least some of the competition risk faced by ATCO Pipelines may have resulted from the growth of the system to connect customers either already served by NGTL or in direct competition with NGTL for those loads. The Board also notes that ATCO's largest customer is ATCO Gas, which, in the Board's view, has little credit risk. In any event, the Board considers that it should establish capital structures for 2004 based on the business risks that exist at the time of this Proceeding. The Board does not consider that it should speculate on the possible resolution of outstanding pipeline competition issues.

The Board notes that in NGTL's last Phase I proceeding,[122] the Board indicated that there would be a proceeding to address outstanding gas pipeline competition issues (the Competitive Pipeline Module). The Board considers that the Competitive Pipeline Module is the appropriate forum to

[122] Application 1315423, Transcript Volume 1, pages 44-49

deal with the inter-pipeline competition matters that may impact the business risks presently confronting ATCO Pipelines.

The Board directs ATCO Pipelines, at the time of its first GRA following the Board's decision in the Competitive Pipeline Module, to apply either:

a) For a change to its deemed equity ratio, to reflect the change in business risk arising from any directions contained within such a decision; or

b) For maintenance of its then existing capital structure on the basis that no change to business risk resulted from the decision in the Competitive Pipeline Module.

The Board notes that CG recommended that the equity ratio of ATCO Pipelines be set at 40%, which was 8% higher than its recommendation for NGTL, while Calgary/CAPP's recommendation for the equity ratio of ATCO Pipelines at 38% was 5% higher than its recommended equity ratio for NGTL.

The Board notes that if the interveners' differentials were applied to the Board's 35% determination for NGTL, the result would be a range of 40% to 43% for ATCO Pipelines.

The Board agrees with all parties that ATCO Pipelines has higher business risk than NGTL.

The Board notes that the last Board decision for ATCO Pipelines, Decision 2003-100, set the 2003 common equity ratio for both ATCO Pipelines North and ATCO Pipelines South at 43.5%.

Regarding gas transmission companies with higher risk than NGTL, the Board notes Dr. Evan's evidence[123] that Pacific Northern Gas (PNG) had an awarded equity ratio of 42.9% and an adjusted actual equity ratio of 44.2%, with a credit rating of BBB (low). The Board also notes Dr. Booth's view[124] that PNG is a highly risky utility and Dr. Robert's view[125] that PNG is riskier than the other utilities.

The Board also notes that ATCO Pipelines has preferred shares in its capital structure. Although the preferred shares provide additional support to the capital structure, in this analysis, the Board has evaluated the appropriate common equity ratio as if the company had no support from its preferred shares.

Considering all of the above, the Board concludes that an appropriate common equity ratio for ATCO Pipelines is 43.0%.

The Board will further address the issue of ATCO's preferred shares below.

5.3 Electric and Gas Distribution

The Board will now consider the appropriate capital structures for the electric and gas distribution Applicants in light of the 5 topic areas set out in section 5.1 as shown below:

1. The business risk of each utility sector and Applicant;

[123] Exhibit 021-24
[124] Exhibit 016-11(a), Evidence of L. D. Booth, page 54
[125] Transcript, Volume 34, page 5602

2. The Board's last-approved equity ratio for each Applicant (where applicable);
3. Comparable awards by regulators in other jurisdictions;
4. Interest coverage ratio analysis; and
5. Bond rating analysis.

Business Risk

The Board notes the consensus that electric distribution companies are subject to more business risk than electric transmission companies, principally due to their recovery of a significant amount of fixed costs in variable charges and their greater exposure to credit risks.

ATCO proposed that the difference in the equity ratio between its electric distribution companies and its electric TFO should be 12.0-17.0%. The Board observes that 5%-10% of this difference in the equity ratio was due to ATCO's perception of a higher regulatory risk following the passage of the *RDS Amendment Regulation*.[126]

The Board is not persuaded that the *RDS Amendment Regulation* has materially increased the risk to an electric distribution company that has appointed a third-party as RRT provider. The Board notes that the requirement for an electric distribution company to provide a hedged rate is contingent on the default of its RRT provider. The Board notes that it did not receive evidence regarding what contractual protections and security, if any, are available to ATCO in the event of a default by its appointed RRT provider. Also, it is possible that a default would be foreseeable over some period of time prior to it occurring, which may permit time to implement contingency plans to minimize associated impacts. Further, in the event of such a default, an application could be made to the Board to recover, from customers, prudent costs incurred by the electric distribution company in resuming the provision of the RRT. The Board would then consider the merits of such an application, considering factors such as the contractual circumstances and remedies available to the electric distribution company, the circumstances of the RRT appointment, and the potential harm to customers. The Board also notes that no other electric distribution company filed evidence asserting a similar increase in risk.

ATCO also argued that its electric distribution company had higher risk than its electric TFO as a result of potential franchise loss. However, in light of the lack of recent actual occurrences of municipalities closing a transaction pursuant to an option to acquire utilities assets, the Board does not consider, at this time, that the risk of franchise loss or of a municipality acquiring utility assets has increased over what it has been historically. Should there be a material change in the business risk arising from risk of franchise loss an affected utility could apply to the Board at that time to seek appropriate relief.

As shown in Table 8, the Companies, CG and Calgary/CAPP all recommended equity ratios for fully taxable electric distribution companies that were 5% higher than their recommended equity ratios for fully taxable electric transmission companies. The Board understands that this does not necessarily mean that the recommended differential would always be 5%.

ATCO considered the business risk of ATCO Gas to be lower than the business risk of its electric distribution company due to ATCO's perception of a higher regulatory risk for its

[126] Ministerial Order 73/2003, November 4, 2003

electric distribution company. As discussed above, the Board does not agree with ATCO's perception of the magnitude of the regulatory risk for its electric distribution company.

The Board notes that Calgary/CAPP and CG considered that ATCO Gas has the same or slightly higher business risk than a fully taxable electric distribution company, due to higher volatility of revenue resulting from a different rate design and higher sensitivity to fluctuations in weather conditions.

The Board agrees that a gas distribution company has slightly more risk than a taxable electric distribution company due to higher revenue volatility. The Board does not agree with ATCO that the higher revenue volatility of ATCO Gas is more than offset by higher regulatory risk for electric distribution companies.

The Board notes from Table 8 that parties making recommendations, other than ATCO Gas, suggested that the difference between the equity ratio for ATCO Gas and the equity ratio for a fully-taxable electric distribution company should be in the range of 0-2%.

The Board concludes that electric distribution companies have higher business risks than electric transmission companies, and that gas distribution companies have slightly higher business risk than electric distribution companies.

The Board considers that business risk, in isolation, would indicate that gas distribution companies should have a common equity ratio that is 0-2 % higher than the equity ratio for fully taxable electric distribution companies.

Comparison to Previous Board Awards

The Board notes from Table 8 that the most recent equity ratio approved by the Board for a taxable electric distribution company was 35%, and the most recent equity ratio approved by the Board for fully-taxable electric transmission companies was 32%, a difference of 3%. Earlier in this Decision, the Board determined an equity ratio of 33% for taxable electric transmission companies. The Board considers that this factor, in isolation, would indicate an equity ratio of 36% for the taxable electric distribution companies. Since the Board considers that ATCO Gas has slightly higher business risk than the electric distribution companies, the Board considers that this factor, in isolation, this would indicate an equity ratio of more than 36% for ATCO Gas.

The Board notes from Table 8 that the last equity ratio approved for ATCO Gas was 37%, established in Decision 2003-072. The Board considers that the business risks of ATCO Gas have not changed materially from those assessed by the Board in this prior decision, which, in isolation, would indicate an equity ratio for ATCO Gas of 37%.

Comparable Awards by Regulators in Other Jurisdictions

The Board notes its earlier caveats on relying on comparable awards by other regulators in a previous section of this Decision.

The Board notes that the gas distribution companies in Ontario, Enbridge Gas and Union Gas have been awarded a common equity ratio of 35 to 37% and a total equity ratio of 38 to 40%, treating preferred shares as 80% equity.[127]

[127] Exhibit 021-24

The Board considers that this information, in isolation, would indicate that the equity ratio for ATCO Gas could be maintained at its current level of 37%.

The Board does not consider that there are any other electric distribution companies in Canada that are comparable to the electric distribution companies in the restructured electric industry in Alberta.

Interest Coverage Ratio Analysis

The Board notes that Enbridge Gas has been awarded an S&P rating of "2".[128] The Board notes Ms. McShane's estimate that ATCO Gas would warrant an S&P risk profile of between "2" and "3". The Board notes that Ms. McShane estimates an S&P risk ranking of "3" for ATCO Electric. However, the Board earlier noted its view that ATCO had over-stated the business risk level of ATCO Electric. In the Board's view, an appropriate S&P risk score for both distribution utilities is between "2" and "2.5".

The S&P guidelines indicate that for a utility with a risk ranking of "2", a pretax interest coverage ratio in the range of 2.3 to 2.9 times is indicated for an "A" debt rating.

Similarly, the S&P guidelines indicate, through pro-rating the guidelines for a "2" and for a "3", that for a utility with a risk ranking of "2.5", a pretax interest coverage ratio in the range of 2.55 to 3.15 times is indicated for an "A" debt rating.

The Board refers the reader to the Interest Coverage Ratio Analysis section provided earlier in the Electric and Gas Transmission section, including the DBRS guidelines indicated there, as additional factors to consider for determining the appropriate common equity ratio for either an electric or a gas distribution company.

Based on this evidence, the Board concludes that an acceptable pretax interest coverage ratio for a taxable electric distribution company distribution company is at or above 2.2 times.

The Board considers that this factor, in isolation, indicates an equity ratio for taxable electric distribution companies and for gas distribution companies higher than the currently approved 35% for ATCO Electric Distribution.

The Board considers gas distribution companies to have slightly more risk than electric distribution companies and, therefore, the Board considers that this factor, in isolation, indicates that gas distribution companies should have slightly more equity than electric distribution companies.

Bond Rating Analysis

The Board notes that Aquila is the only electric or gas distribution company regulated by the Board with its own bond rating. From Table 10, the Board notes that Aquila has a DBRS rating of A (low) based on an equity ratio of 40 to 45.5%. However, the Board notes that Aquila has a

128 Exhibit 005-11-1, Capital Structures for the ATCO Utilities, Kathleen McShane, page 11

substantial amount of goodwill[129] on its books, amounting to approximately 29% of its assets at the time of the DBRS report, which would require equity support compared to a distribution company without goodwill. Therefore, based on this factor in isolation, the Board concludes that the target equity ratio for a taxable electric distribution company is somewhat below 40%.

The Board considers the most comparable other Canadian gas and electric distribution companies, available in Dr. Evan's evidence, to be Union Gas and Enbridge Gas.

The Board notes that Union Gas Ltd. has an adjusted actual equity ratio of 35% and credit ratings of A and A-.[130] The Board notes that Enbridge Gas has an adjusted actual equity ratio of 51% and credit ratings of A and BBB+.[131] The Board notes that the date of the adjusted actual equity ratio date is not necessarily the same as the dates of the two credit reports. The Board considers this broad range of adjusted actual equity ratios for Ontario gas distribution utilities and its impact on bond ratings to be of little assistance in this Proceeding.

<u>Conclusion</u>
At the beginning of this section, the Board indicated that it would consider a variety of factors for its determination of the appropriate level of equity in the capital structure of electric and gas distribution companies.

As discussed in the preceding sections, in the Board's view, setting an appropriate equity ratio is a subjective exercise that involves the assessment of several factors and the observation of past experience. The assessment of the level of business risk of the utilities is also a subjective concept. Consequently, the Board considers that there is no single accepted mathematical way to make a determination of equity ratio based on a given level of business risk.

The following table summarizes the indicated equity ratios that arise from various factors as discussed in the earlier sections:

Table 12. Indicated Common Equity Ratios for Distribution Companies by Factor

Factor	Indicated Electric Distribution	Indicated Gas Distribution
Business Risk	Lowest for Distribution	Electric DISCO + 0-2%
Previous Board Awards	~36%	~37%
Awards in Other Jurisdictions	N/A	~37%
Interest Coverage Ratio Analysis	>35%	>35%, >DISCOs
Bond Rating Analysis	<40%	N/A

After considering all of the above factors and after applying its judgment, the Board concludes that an appropriate common equity ratio for a fully taxable electric distribution company with no preferred shares is 37.0%, and that an appropriate common equity ratio for a gas distribution company is 38.0%.

The Board will now consider each electric and gas distribution Applicant, individually.

129 Exhibit 004-12, July 31, 2002 DBRS Report on Aquila, page 5 indicating 54.5% net debt at March 31, 2002 (implies 45.5% equity), and indicating 40.0% deemed equity at December 31, 2001; and Decision 2004-035, page 18
130 Exhibit 021-24
131 Ibid.

5.3.1 FortisAlberta/Aquila

The Board considers that FortisAlberta (formerly Aquila) does not have any material differences in business risk from the typical electric distribution company.

The Board notes that Aquila is a fully taxable electric distribution company with no preferred shares.

Therefore, for the same reasons that were provided above, the Board concludes that an appropriate common equity ratio for FortisAlberta is 37.0%.

5.3.2 ATCO Electric Distribution

The Board considers that ATCO Electric Distribution does not have any material differences in business risk from the typical electric distribution company.

The Board also notes that ATCO Electric Distribution has preferred shares in its capital structure. Although the preferred shares provide additional support to the capital structure, in this analysis, the Board has evaluated the appropriate common equity ratio as if the company had no support from its preferred shares.

The Board concludes that an appropriate common equity ratio for ATCO Electric Distribution is 37.0%.

The Board will further address the issue of ATCO's preferred shares below.

5.3.3 ENMAX Distribution

The Board considers that ENMAX Distribution does not have any material differences in business risk from the typical electric distribution company.

The Board notes ENMAX's argument that it has additional risks due to its municipal ownership, including a fixed dividend requirement, lack of equity access, and the change in regulator, and that as a result it required a capital structure with 50% common equity.

The Board does not agree with ENMAX that its fixed dividend or lack of access to public equity markets raises its risks in the circumstances. In the Board's view, having established a fair return, the Board need not concern itself with the particular internal policies to which a utility may be subject regarding distributions of dividends or acquisition of equity. The Board also considers that the change in regulator for ENMAX does not result in ENMAX having higher risks, all else being equal, than other electric distribution companies regulated by the Board.

With respect to the ENMAX DISCO, which just came under Board jurisdiction in 2004, the capital structure determined in this Proceeding is based on the assumption that the deferral accounts that the Board will ultimately approve for this Applicant will not be materially different than those in existence at the time of this Proceeding for FortisAlberta/Aquila and ATCO Electric Distribution.

For the same reasons that were provided with respect to EPCOR Transmission above, the Board concludes that the equity ratio for a non-taxable electric distribution company should be 2.0% higher than the equity ratio for a fully taxable electric distribution company.

Therefore, the Board concludes that an appropriate common equity ratio for ENMAX Distribution is 39.0%.

5.3.4 EPCOR Distribution

The Board considers that EPCOR Distribution does not have any material differences in business risk from the typical electric distribution company.

With respect to the EPCOR Distribution, which came under Board jurisdiction in 2004, the capital structure determined in this Proceeding is based on the assumption that the deferral accounts that the Board will ultimately approve for this Applicant will not be materially different than those in existence at the time of this Proceeding for FortisAlberta/Aquila and ATCO Electric distribution companies.

For the same reasons that were provided with respect to ENMAX Distribution above, the Board concludes that an appropriate common equity ratio for EPCOR Distribution is 39.0%.

5.3.5 ATCO Gas

The Board considers that ATCO Gas does not have any material differences in business risk from the typical gas distribution company.

The Board notes that ATCO Gas also has preferred shares in its capital structure. Although the preferred shares provide additional support to the capital structure, in this analysis, the Board has evaluated the appropriate common equity ratio as if the company had no support from its preferred shares.

As determined above, the Board concludes that an appropriate common equity ratio for ATCO Gas is 38.0%.

The Board will further address the issue of ATCO’s preferred shares below.

5.3.6 AltaGas

The Board considers that AltaGas has greater business risk than the typical gas distribution company.

AltaGas and ATCO Gas considered the business risks of AltaGas to be higher than the business risks of ATCO Gas, due to AltaGas’ relatively small size, rural service area, geographically dispersed customers and high level of customer contributions.

Calgary/CAPP was the only party who took the position that AltaGas did not have higher business risks than ATCO Gas. Calgary/CAPP considered the main risk to AltaGas to be commodity cost risk, for which AltaGas has a deferral account. As a result, Calgary/CAPP recommended the same equity ratio for AltaGas as for ATCO Gas.

The Board notes that AltaGas' parent has a credit rating of BBB (low) and has been unable to raise debt with a term longer than five years. AltaGas had the view that, due to its size, it was very unlikely that it would be able to access debt on more favourable terms than its parent.[132]

The Board notes that AltaGas' parent is involved in a significant level of non-regulated activities. The Board is unable to establish the effect that those activities have on the parent's rating. The Board is not persuaded that that AltaGas would not have a higher rating than its parent and that it would not be able to access debt on more favourable terms than its parent. Nonetheless, the Board is persuaded that the business risks of AltaGas are greater than the business risks of a typical gas distribution company because of the nature of its service territory, not necessarily because of its smaller size.

The Board notes that CG's recommended equity ratio for AltaGas was 3% higher than its recommended equity ratio for ATCO Gas, whereas AltaGas and ATCO considered that the equity ratio for AltaGas should be 5% higher. The Board considers that this factor, in isolation indicates that the equity ratio for AltaGas should be 41-43%.

The Board notes that the previous Board approved equity ratio for AltaGas was 41%.

Considering all of the above, the Board concludes that an appropriate common equity ratio for AltaGas is a continuation of its currently approved 41%.

5.4 Utility-Specific Adjustments to ROE

Some parties in this Proceeding indicated that when a common ROE approach is used, it might be necessary to consider a utility-specific adjustment to the common ROE to adequately reflect the investment risks of individual utilities.

In particular, the Board notes that ATCO Pipelines indicated that an adjustment to its ROE was required to adequately compensate its investors for the risks confronting the company, because adjustments to capital structure would not be sufficient.

As noted earlier in this Decision, the Board considers that unique utility-specific adjustments to the generic ROE should only be made in exceptional circumstances where adjusting capital structure alone is not sufficient to reflect the investment risk for a particular Applicant.

The Board notes that the equity ratio approved for ATCO Pipelines in this Decision is marginally lower than the last Board-approved equity ratio for ATCO Pipelines. The Board considers that the capital structure for ATCO Pipelines in this Decision adequately reflects the investment risk for ATCO Pipelines.

The Board concludes that there is no need for utility-specific adjustments to the common ROE for any of the Applicants.

5.5 2004 Deemed Common Equity Ratios

Based on the Board's findings above, the Board approves the following deemed common equity ratios for 2004:

[132] AltaGas Argument, page 32

Table 13. Board Approved Equity Ratios

	Last Board-Approved Common Equity Ratios (%)	2004 Board Approved Common Equity Ratios (%)	Change in Approved Common Equity Ratio (%)
ATCO TFO	32.0	33.0	1.0
AltaLink	34.0[133]	35.0	1.0
EPCOR TFO	35.0	35.0	0.0
NGTL	32.0	35.0	3.0
ATCO Electric DISCO	35.0	37.0	2.0
FortisAlberta (Aquila)	N/A [134]	37.0	N/A
ATCO Gas	37.0	38.0	1.0
ENMAX DISCO	N/A [135]	39.0	N/A
EPCOR DISCO	N/A [125]	39.0	N/A
AltaGas	41.0	41.0	0.0
ATCO Pipelines	43.5	43.0	(0.5)

5.6 ATCO Utilities Preferred Shares

In earlier sections, the Board noted that the 2004 approved common equity ratios in this Decision for the ATCO utilities were not adjusted to reflect any impact of ATCO's use of preferred shares. The Board notes that there was essentially no evidence presented regarding the impact of preferred shares on the required common equity ratios.

The Board has recognized in previous decisions that during the period of time when income tax rebates were in place, it was prudent to utilize preferred share financing in place of debt.

However, the Board considers that there may be merit in further consideration of the appropriateness of the continuing use of preferred shares as a form of financing, to understand the redemption options and to fully explore the related implications and options.

The Board directs ATCO to address the appropriateness of the continuing use of preferred shares as a form of financing, in the next Phase 1 GRA/GTA for ATCO Gas, ATCO Pipelines or ATCO Electric, whichever comes first.

5.7 Process to Adjust Capital Structure

The Board notes that all parties, except for CG, considered that it would be appropriate to address any future changes in capital structure in utility-specific GRA/GTAs. CG proposed a scheduled review of the capital structures of all Applicants.

The Board agrees with the general consensus that it would be more appropriate to address any future changes in capital structure in utility-specific GRA/GTAs. The Board also agrees with the general consensus that such changes should only be pursued if parties perceive that there has

133 In Decision 2003-061, the Board approved an equity ratio for AltaLink of 32%, plus an additional 2% to offset the impact on the interest coverage ratio of a partial allowance of income taxes in the revenue requirement.

134 The Board did not specifically approve this ratio; it was part of a negotiated settlement approved in Decision 2003-019, which included a deemed 40% equity ratio as one of many settled parameters of the revenue requirement.

135 Both EPCOR and ENMAX Distribution were subject to Board jurisdiction effective January 1, 2004.

been a material change in investment risk since the time of this Proceeding, except as otherwise specifically directed in this Decision.

6 DIRECTIONS TO APPLICANTS

The Board directs any Applicant that has a Board-approved revenue requirement for 2004 that includes a placeholder for ROE and/or capital structure to file with the Board by August 1, 2004, for information, its plans on how it intends to comply with any outstanding directions from the Board to replace the placeholders for ROE and/or capital structure, when these changes might be reflected in customer rates, and the magnitude of the impact on customer rates for the changes arising from this Decision. The Board would appreciate being advised of the status and magnitude of any other known adjustments to rates that might be forthcoming in the same timeframe as the adjustments arising from this Decision.

With respect to applications to establish a 2004 revenue requirement that are currently before the Board for a decision, the Board will use the 2004 generic ROE and capital structure approved in this Decision.

With respect to applications presently before the Board and future applications to establish a revenue requirement for 2005 or later, the Board will apply the generic ROE for that year resulting from the adjustment mechanism approved in this Decision and the capital structure provided for in this Decision, barring the applicant demonstrating a material change has occurred requiring adjustment to capital structure.

7 SUMMARY OF BOARD FINDINGS AND CONCLUSIONS

This section is provided for the convenience of readers. In the event of any difference between the Approvals in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. With respect to the Jurisdictional Question itself, the Board finds that the proper interpretation of section 37 of the GUA would allow the Board to determine the capital structure for the relevant test period (2004 or 2005) for each gas utility under its jurisdiction by way of a generic proceeding and to establish a standardized approach based on a formula for determining the return on common equity for gas utilities. 7

2. Accordingly, the Board finds that the evidence in the Proceeding indicates that implementation of a generic approach is in the public interest and accordingly, the Board will implement a generic approach to ROE and capital structure. In the following sections, the Board will address the issues associated with the determinations necessary to appropriately implement this approach. 11

3. The Board will therefore establish a common, or generic, ROE to be applied to all Applicants. The Board will address the need for any utility-specific adjustments to the common ROE in the capital structure section of this Decision. 14

8 SUMMARY OF BOARD DIRECTIONS

This section is provided for the convenience of readers. In the event of any difference between the Directions in this section and those in the main body of the Decision, the wording in the main body of the Decision shall prevail.

1. The Board directs ATCO Pipelines, at the time of its first GRA following the Board's decision in the Competitive Pipeline Module, to apply either:... 47
   a) For a change to its deemed equity ratio, to reflect the change in business risk arising from any directions contained within such a decision; or 47
   b) For maintenance of its then existing capital structure on the basis that no change to business risk resulted from the decision in the Competitive Pipeline Module. 47
2. The Board directs ATCO to address the appropriateness of the continuing use of preferred shares as a form of financing, in the next Phase 1 GRA/GTA for ATCO Gas, ATCO Pipelines or ATCO Electric, whichever comes first. 55
3. The Board directs any Applicant that has a Board-approved revenue requirement for 2004 that includes a placeholder for ROE and/or capital structure to file with the Board by August 1, 2004, for information, its plans on how it intends to comply with any outstanding directions from the Board to replace the placeholders for ROE and/or capital structure, when these changes might be reflected in customer rates, and the magnitude of the impact on customer rates for the changes arising from this Decision. The Board would appreciate being advised of the status and magnitude of any other known adjustments to rates that might be forthcoming in the same timeframe as the adjustments arising from this Decision. 56

9 ORDER

For and subject to the reasons set out in this Decision, IT IS HEREBY ORDERED THAT:

1. With respect to Applicants that have a Board-approved revenue requirement for 2004 that includes a placeholder for ROE and/or capital structure, the placeholder for ROE shall be replaced by 9.60% and the placeholder for capital structure shall be replaced as set out in this Decision;

2. With respect to applications by an Applicant to establish a 2004 revenue requirement that are currently before the Board, the Board shall apply an ROE of 9.60% and shall apply the capital structure as set out in this Decision; and

3. With respect to current or future applications by an Applicant to establish a revenue requirement for 2005 or later years, the Board shall apply the common ROE for that year resulting from the adjustment mechanism approved in this Decision and shall apply the capital structure as set out in this Decision for such Applicant, unless the Applicant can demonstrate to the satisfaction of the Board that there has been a material change in business risk that warrants a change to the capital structure set out in this Decision.

Dated in Calgary Alberta on July 2, 2004.

ALBERTA ENERGY AND UTILITIES BOARD

(original signed by)

A. J. Berg, P. Eng
Presiding Member

(original signed by)

R. G. Lock, P. Eng
Member

(original signed by)

J. I. Douglas, FCA
Member

APPENDIX 1 – HEARING PARTICIPANTS

Name of Organization (Abbreviation) Counsel or Representative (APPLICANTS)	Witnesses
AltaGas Utilities Inc. (AltaGas) F. Martin R. Jeerakathil	L. Heikkinen K. McShane
AltaLink Management Ltd. (AltaLink) H. Williamson	Dr. R. Evans K. Johnston D. Frehlich J. Harbilas
Aquila Networks Canada (Alberta) Ltd. (Aquila) T. Dalgleish	Dr. R. Evans
ATCO Utilities (ATCO) L. Smith	K. McShane J. McNeil D. Belsheim O. Edmondson
ENMAX Power Corporation (ENMAX) L. Cusano D. Wood	R. Henderson A. Buchignani R. Falconer Dr. J. Neri
EPCOR Utilities Inc. (EPCOR) D. Crowther	Dr. R. Evans
NOVA Gas Transmission Ltd. (NGTL) K. Yates Ms. Moreland D. Holgate	R. Girling S. Brett G. Lackenbauer P. Murphy Dr. P. Carpenter M. Feldman S. Pohlod Dr. W. Langford A. Jamal G. Zwick Dr. L. Kolbe Dr. M. Vilbert

Name of Organization (Abbreviation) **Counsel or Representative (INTERVENERS)**	**Witnesses**
Alberta Association of Municipal Districts and Counties, Federation of Alberta Gas Co-ops Ltd., Gas Alberta Inc. and Municipal and Gas Co-op Intervenors (AAMDC) T. Marriott	
Alberta Federation of REAs (REAs) K. Sisson	
Alberta Irrigation Projects Association (AIPA) H. Unryn	
BP Canada Energy Company (BP) D. McGrath	
Canadian Association of Petroleum Producers (CAPP) N. Schultz	Dr. L. Booth M. Romanow G. Stringham P. Tahmazian D. Gilbert M. Pinney T. Kelley P. Nettleton
Canadian Gas Association (CGA) P. Jeffrey	M. Cleland P. Case
Cargill Power & Gas Markets (Cargill) M. Stauft	
Cities of Lethbridge and Red Deer (Cities) P. Smith	
City of Calgary (Calgary) P. Quinton-Campbell R. Brander	K. Sharp H. Johnson J. McCormick Dr. L. Booth
Consumers Coalition of Alberta (CCA) J. Wachowich	
Consumers Group/AUMA (Consumers Group) J. Bryan	W. Marcus R. Liddle Dr. L. Kryzanowski Dr. G. Roberts
First Nations Communities (First Nations) J. Graves A. Ackroyd	
Fortis Alberta Holdings Inc. (Fortis) B. Ho	

Name of Organization (Abbreviation) **Counsel or Representative (INTERVENERS)**	**Witnesses**
Industrial Power Consumers Association of Alberta (IPCAA) M. Forster D. Macnamara	
Independent Power Producers Society of Alberta/Senior Petroleum Producers Association (IPPSA/SPPA) L. Manning	D. Hildebrand A. Moon J. Keating
Nexen Inc. (Nexen) S. Young	
Public Institutional Consumers of Alberta (PICA) N. McKenzie	
Utilities Consumers Advocate (UCA) R. McCreary R. Jackson	

BOARD STAFF B. McNulty (Board Counsel) J. Wilson S. Allen W. Taylor R. Litt R. Schroeder Dr. V. Mehrotra	

APPENDIX 2 – ABBREVIATIONS

AESO	Alberta Electric System Operator
ANG	Alberta Natural Gas Ltd.
ATWACC	After Tax Weighted Average Cost of Capital
CAPM	Capital Assets Pricing Model
CE Test	Comparable Earnings Test
DCF Test	Discounted Cash Flow Test
DISCO	Electric or Gas Distribution Utility
ECAPM	Empirical Capital Assets Pricing Model
Equity Ratio	Common Equity as a Percentage of Total Financing
ERP Test	Equity Risk Premium Test
Foothills	Foothills Pipelines Inc.
GRA/GTA	General Rate Application/General Tariff Application
MRP	Market Risk Premium
NEB	National Energy Board
ROE	Rate of Return on Common Equity
RTO	Regional Transmission Organization
S&P	Standard & Poor's
TFO	Electric Transmission Facility Owner
TQM	Trans Quebec and Maritimes Pipeline

APPENDIX 3 – BOARD LETTER OF SEPTEMBER 30, 2002

"2002-09-30 EUB Letter.doc"

(Consists of 8 pages)

Also, within this embedded document there are two further embedded documents.
(Appendix B consists of 5 pages and Appendix C consists of 1 page)

Alberta Energy and Utilities Board

Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

File No. 5681-1

September 30, 2002

Sent to Parties on Various Utility Branch Lists via Email

Dear Sir/Madam:

PROCEEDING NO. 1271597
GENERIC COST OF CAPITAL HEARING - ELECTRIC AND GAS UTILITIES
- **Notice of Registration as Intervenors**
- **Notice of Pre-hearing Meeting – November 26, 2002**

On May 6, 2002, the Board received a request from the City of Calgary (Calgary) that the Board institute a proceeding to consider generic cost of capital matters for electric and gas utilities under the Board's jurisdiction. The Board responded to Calgary by letter dated June 6, 2002. Copies of both letters are attached as Appendix B and Appendix C[1], respectively.

The Board has decided to call a generic hearing pursuant to its powers to hold an inquiry under Section 46 of the *Public Utilities Board Act* (PUB Act) to consider cost of capital matters for electric, gas and pipeline utilities under its jurisdiction. This would include pipeline and electric transmission companies as well as electric and gas distribution companies.

The Board will hold a pre-hearing meeting as specified below to deal with the following issues:

- Determination of the scope of the proceeding and list of issues
- Determination of procedural matters that might be adopted for such a hearing.

A preliminary list of issues and procedural matters that the Board will consider through such a process is attached to this letter as Appendix A.

The Board requests that interested parties consider this preliminary list of issues and procedural matters and provide the Board with their detailed written submissions on the appropriateness of each issue or matter as well as their submissions with respect to additional issues or matters that might appropriately be considered through such a generic proceeding.

[1] Please note that these Appendices are embedded and may take a second or two to appear.

The following are key dates that the Board has established as follows:

Registration as intervenors with the Board	October 18, 2002
Written Submissions: List of Issues and Procedural Matters	November 12, 2002
Pre-Hearing Meeting	November 26, 2002
Hearing (Preliminary Schedule)	2nd Quarter 2003

After receiving parties' written submissions the Board will prepare a consolidated list of issues and procedural matters for discussion at the pre-hearing meeting.

The pre-hearing meeting will be held as follows:

- DATE: November 26, 2002
- TIME: 9:00 a.m.
- PLACE: Govier Hall, EUB Calgary offices (2nd floor, 640 – 5 Avenue SW)

The generic hearing would likely be scheduled for the 2nd quarter of 2003.

The Board is prepared to consider submissions respecting cost recovery for this proceeding given possible future cost savings associated with streamlining of the Cost of Capital determination process. The Board has the ability to allow costs of the proceeding and to direct that such costs be borne by consumers through the utilities' hearing cost reserve accounts pursuant to the Board's discretion under Section 68 of the PUB Act and pursuant to Rules 55 and 57 of the Board's Rules of Practice.

The Board would appreciate the efforts of any or all parties to work together, in advance of the pre-hearing meeting, in order to consolidate and simplify the views of parties on any matter, including procedural and timing issues.

Any questions or correspondence, including submissions, should be directed to the writer in the EUB's Calgary office. I can be reached at (403) 297-3539 telephone, (403) 297-6104 fax, or via email at jim.wilson@gov.ab.ca. Parties should also file an electronic copy of their registrations and any submissions at the email address eub.utl@gov.ab.ca.

Yours truly,

(Original signed " J. Wilson")

Jim Wilson
Lead Application Officer

Attachments

APPENDIX A

Preliminary List of Issues and Procedural Matters

A preliminary list of issues and procedural matters that will be considered at a pre-hearing meeting for a EUB generic hearing into utility cost of capital matters.

For clarity, the Board will not be discussing the merits of each issue in the list below (i.e. in section **I. Preliminary List of Issues)** but the Board, in its Decision arising from the pre-hearing meeting, will determine the scope of the proceeding.

Further, the Board will make determinations, in its Decision arising from the pre-hearing meeting, on procedural items listed below (i.e. in section **II. Preliminary List of Procedural Matters**)

I. Preliminary List of Issues

A. Pros and Cons of a Standardized Approach

1) In general and without specifying which methodology (ies) might be used, what are the pros and cons of adopting a standard methodology (ies) for setting equity rate of return in utility rate cases?

2) In general and without specifying which methodology (ies) might be used, what are the pros and cons of adopting a standard methodology (ies) for setting capital structure in utility rate cases?

3) Is the adoption of a generic approach to utility equity rate of return and capital structure in keeping with developments in other jurisdictions in North America?

B. Alternatives within a Standardized Approach

1) Assuming that the establishment of a standardized approach to setting equity rate of return is desirable:

    i. What options or alternatives should the Board consider? For example, the comparative earnings method, the risk premium method, the discounted cash flow method, ATWACC, and the NEB's approach that includes an adjustment formula.

    ii. What are the pros and cons of each option or combination of options?

2) Assuming that the establishment of a standardized approach to setting utility capital structures is desirable:

   i. What options should the Board consider?

   ii. What are the pros and cons of each option or combination of options?

C. Standardized vs. One-by-One Approach?

1) Would it be correct to consider a standardized approach to setting utility equity rate of return for all types of utilities under the Board's jurisdiction, including gas transmission, gas distribution, gas retail, electric transmission, electric distribution and electric regulated rate option providers?

2) Would it be correct to consider a single standardized approach to setting utility capital structure for all types of utilities under the Board's jurisdiction, again including gas transmission, gas distribution, gas retail, electric transmission, electric distribution and electric regulated rate option providers?

3) What principles should guide the determination of capital structure for utilities that are owned by holding companies, i.e. what principles and issues should be taken into account in dealing with a deemed vs. actual capital structure?

4) What differences exist between investor owned and municipally owned utilities that affect determination of cost of capital issues and how should those differences be taken into account with respect to cost of capital issues including return on equity, capital structure, debt costs and income tax?

D. Timing Issues

1) The Board is considering setting an implementation date for any cost of capital methodology (ies) adopted sufficiently far in advance, so as not to impact rate cases or settlement negotiations occurring during the generic hearing process. Alternately, the Board could direct parties to use placeholders for rate of return and capital structure with respect to applications not presently before the Board. What are the pros and cons of each approach?

2) What are the implications of the substance and timing of a cost of capital generic hearing with respect to the possible regulation by the Board of municipally owned utilities?

3) Should the Board consider setting an expiry date or a mandatory review date for any methodology (ies) it may determine to be appropriate for cost of capital issues? If so, what is an appropriate length of time that should elapse before a review is required?

4) How should adjustments in equity rate of return and capital structure be dealt with between test periods?

E. Special Considerations

1) Should parties have the option of agreeing, through a negotiated settlement process, on an equity rate of return and/or capital structure that is different from the equity rate of return and/or capital structure that would result using the standardized approach?

2) What provision, if any, would an inquiry into cost of capital issues need to make with respect to the Performance Based Rates (PBR) methodology or other evolving methodologies for setting rates or rate components?

3) Should the Board consider negotiated pricing arrangements in respect of expansion or merchant projects as a substitute for traditional forms of earning through equity rate of return and capital structure, (for example the Alliance Pipeline)?

II. Preliminary List of Procedural Matters

A. One or Two Phases

1) At a generic hearing:

   i. Should the Board conduct a single-phase hearing to consider both equity rate of return and capital structure generic issues?

   ii. Alternately, should there be two separate phases, one into equity rate of return applicable to all types of utilities and the other into capital structure for each type of utility?

   iii. Should the proceeding be with respect to all utilities or do the distinctions between gas, pipeline and electric industries merit separate and distinct generic hearings or phases?

B. Schedule for the Proceeding

1) Designation of "Applicant(s)" for initial evidence submission

2) Desired Process and dates for the following:

   i. Initial Evidence
   ii. IRs
   iii. Response to IRs
   iv. Intervenor Evidence
   v. IRs to Intervenors
   vi. Response to IRs to Intervenors
   vii. Rebuttal Evidence

C. Costs

1) With respect to costs for the generic hearing(s):

   i. Should some parties be only partially funded?

   ii. If so, which parties should this apply to?

   iii. How could parties be provided with incentives to combine positions where possible to achieve cost and time efficiencies?

APPENDIX B

City of Calgary Letter dated May 6, 2002

"Appendix B.doc"

(Consists of 5 pages)

Please note that the above Appendix is embedded and may take a second or two to appear.

APPENDIX C

Board Letter dated June 6, 2002

"Appendix C.doc"

(Consists of 1 page)

Please note that the above Appendix is embedded and may take a second or two to appear.

Burnet,
Duckworth
& Palmer LLP
Law Firm

Reply to: R. Bruce Brander
Direct Phone: **(403) 260-0165**
Direct Fax: **(403) 260-0332**
rbb@bdplaw.com

Assistant: Donna Koenig
Direct Phone: **(403) 260-0186**
Our File: 50343-135

VIA EMAIL

May 6, 2002

Alberta Energy and Utilities Board
640 - 5th Ave. S.W.
Calgary, AB T2P 3G4

Attention: R. D. Heggie
Executive Manager, Utilities Branch

Dear Sirs:

Re: Cost of Capital for Electric and Gas Utilities under the Board's Jurisdiction

Pursuant to the provisions of the *Public Utilities Board Act*, R.S.A. 2000 c. P-45 (the "PUB Act"), the *Gas Utilities Act*, R.S.A. 2000, c. G-5, (the "GUA"), the *Electric Utilities Ac*t, R.S.A. 2000 (the "EUA"), c. E-5, and the A*lberta Energy and Utilities Board Act*, R.S.A. 2000, c. A-17 (the "AEUB Act"), The City of Calgary ("Calgary") hereby applies to the Board to convene a proceeding or inquiry to establish a mechanism for the appropriate cost of capital (return on equity and capital structure] for the gas and electric utilities under the Board's jurisdiction. This Application is being made on behalf of Calgary by its legal counsel Burnet Duckworth & Palmer LLP. The particulars of, and support for, this Application, are provided in the following sections.

Interest of Calgary

As the Board is aware, Calgary has a long history of intervention in regulatory proceedings which impact its citizens. With respect to gas utilities, core customers within Calgary represent approximately 70% of the gas consumption and revenue requirement of ATCO Gas South. Through the ATCO Gas South and ATCO Pipelines South rate structure, core customers within Calgary are also responsible for approximately 40% of the revenue requirement of ATCO Pipelines South. Consumers within Calgary also consume approximately one-sixth of the provincial electrical production, and are affected by the rates charged by the Transmission Facility Owners ("TFO"'s).

Cost of capital (including return on equity, capital structure, and associated income taxes) is a significant portion of the revenue requirement of any regulated utility. Using the applied for amounts for 2001 for ATCO Gas South, return on equity and taxes were about 16% of the revenue requirement, and for ATCO Pipelines South about 33%. Based on the TFO materials filed for 2001, return on equity and associated taxes for ATCO Electric and TransAlta were approximately 35% and 33% respectively (EPCOR Transmission Inc. with no tax was approximately 16%).[1]

[1] The percentages increase significantly if return on rate base is used instead of return on equity.

In recent years Calgary has retained experts to present evidence on cost of capital in several proceedings: Canadian Western Natural Gas 1997/1998 GRA, the 2001 TFO Tarff Applications of ATCO Electric, TransAlta and EPCOR Transmission Inc., the ATCO Gas South 2001/2002 GRA, and the ATCO Pipelines South 2001/2002 GRA. As one of the few parties that can afford to carry the significant cost of presenting evidence in this area, Calgary expects that it will be presenting cost of capital evidence in future proceedings affecting its citizens.

As a result, the citizens represented by Calgary are directly affected by return on equity and capital structure issues

Grounds

As noted above, cost of capital constitutes a significant portion of the revenue requirement of the utilities regulated by the Board. Dealing with cost of capital issues is also a significant portion of hearing costs. Cost of capital is also an area where there are a limited number of experts available and the costs of presenting such expert reports is a substantial cost to an intervention – often at rates that exceed the Board's guidelines.

In the recent ATCO Gas South and ATCO Pipelines South proceedings the return on equity and capital structure experts retained by ATCO and Calgary cost just under $200,000 for each proceeding. In the TFO proceedings for 2001 rates, where the three TFO's each filed separate return on equity evidence, expert witness costs totaled about $711,000 for Calgary, ATCO Electric and TransAlta[2]. In addition to the fees of the cost of capital experts, there are significant additional costs for legal counsel, and other experts, to interact with the cost of capital experts to present the case. Where an intervenor incurs these costs as part of the hearing process, the intervenor not only must carry the cost until a Costs Order is issued, but also bears the risks that the utility will oppose the costs which the intervenor has incurred to benefit all customers, or that hourly rates that are in excess of the Board's guidelines will be denied. In addition, the intervenors also bear the utility's costs through the revenue requirement and the hearing reserve account.

In the ATCO Gas South and ATCO Pipelines South 2001/2002 GRA's the utilities filed identical return on equity evidence. Calgary, as the intervenor dealing with return on equity, then had to file evidence responding to the utilities' return on equity requests in two different proceedings, with two attendances by the experts. In Decisions 2000-96 and 2000-97 dealing with these GRA's, the Board issued identical reasons on return on equity matters[3] and made, *inter alia*, the following observations:

> The Board is concerned that, despite its volume, the nature of the expert evidence provided is ultimately of little probative value to the Board in establishing this important determinant of the utility's revenue requirement.
>
> In particular the Board notes the effect that the application of professional judgement [sic] has on the outcome of the equity risk premium test. This test has been noted to be the mainstay of this Board and other Canadian regulatory boards over recent periods…
> ….

---

[2] Calgary, $163,000 (for evidence on all three TFO's); ATCO Electric TFO, $79,000; TransAlta, $468,000. Calgary has not yet been provided details of EPCOR Transmission Inc.'s costs.
[3] Decision 2000-96 pages 52 – 59; Decision 2000-97 pages 31 - 38.

> Further, these [equity risk premium] estimates are far enough apart that the underlying evidence is of little value to the Board in establishing an accurate and well justified estimate of the utility rate of return required to maintain the financial integrity of the utility in the eyes of investors and the market. Subsequently, the Board must rely on an examination of past awards to CWNG to determine if there is a requirement for adjustments to those awards. The Board is also of the view that alternative methods of determining appropriate utility return may need to be examined for use in future rate cases. (emphasis added)

Other Canadian regulatory boards have addressed concerns with respect to the determination of the appropriate cost of capital by taking what could be called a "generic" or formulaic approach to the issue. These include:

- National Energy Board, Multi-Pipeline Cost of Capital, RH-2-94[4],
- British Columbia Utilities Commission, Return on Common Equity Decision, June 10, 1994, Order G-35-94
- Ontario Energy Board Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities, March 1997,
- Manitoba Public Utilities Board Order 49095, page 50.

In Alberta, there has been some limited discussion of a generic approach to return on equity:

- In the Board's Costs Workshop of June 20, 2000 the question of why intervenors did not reduce costs through a different approach to return on equity was raised. Intervenors responded that they had to deal with the applications as filed by the utilities, and no utility had filed for a formula based approach to return on equity.

- In the 2001 TFO proceeding the evidence of Drs. Booth and Berkowitz on behalf of Calgary recommended the use of an adjustment formula for 2002 return on equity[5]. The issue of a formula based approach to return on equity was briefly discussed during the TransAlta portion of the hearing.[6]

- In the 2001/2002 ATCO Gas South and ATCO Pipelines South GRA's the evidence of Drs. Booth and Berkowitz on behalf of Calgary again suggested consideration of an adjustment formula for 2002.[7]

To date, so far as Calgary is aware, none of the utilities under the Board's jurisdiction has filed an application to have cost of capital determined on a generic or formulaic basis, nor is Calgary aware that any of the utilities are planning on doing so. However, Calgary believes that there will be several proceedings in the near future where cost of capital will have to be addressed. These include:

- ATCO Gas 2003 – 2000x GRA for ATCO Gas North and South combined,

[4] In proceeding RH-4-2001 TransCanada PipeLines Limited sought a review of the RH-2-94 Decision and presented a methodology that the EUB was presented with by TransAlta in the 1999/2000 GTA, and was included in TransAlta's 2001 TFO filing.
[5] Applications 2000132, 2000133 and 2000134, Evidence of Laurence D. Booth and Michael K. Berkowitz, page 75.
[6] 2001/2002 TFO Proceeding, September 25, 2000, Volume 3, pages 497 – 501.
[7] AGS GRA Exhibit 43, Evidence of Laurence D. Booth and Michael K. Berkowitz, page 68; APS GRA Exhibit 69, Evidence of Laurence D. Booth and Michael K. Berkowitz, page 63.

- A combined ATCO Pipelines North and South 2003 – 2000x GRA,

- The ATCO Electric TFO (and DISCO) negotiated settlement expires in 2002, and ATCO Electric has notified the Board that a 2003 – 2005 combined application for Transmission and Distribution will be filed in mid to late second quarter 2002.

- The EPCOR Transmission Inc. TFO negotiated settlement will expire at the end of 2002 and, presumably, a 2003 GRA will result,

- Altalink Management Ltd. TFO will need to file a GRA for 2002 and subsequent years.

In addition to the foregoing there may be other gas and electric utilities, with which Calgary is not involved, that will require rate hearings for 2003 and beyond.

Given the recent history with cost of capital matters, and the likelihood of several hearings in the near future dealing with cost of capital, it is Calgary's view that there would be several advantages to a "generic" cost of capital proceeding:

- *Reduction in expert witness costs.* Even if all of the utilities used different experts for a generic proceeding, there would be a likely cost saving to intervenors in only having to retain cost of capital experts for a single proceeding, instead of for multiple proceedings.

- *Reduction in overall hearing costs.* The fees for cost of capital experts are only a portion of the overall expense of dealing with cost of capital in a hearing. Fees for counsel and other experts to deal with cost of capital matters and present the case are also significant. Calgary would expect that a generic proceeding would result in cost reductions through synergies or economies of scale.

- *Efficiencies in use of Board resources.* Dealing with cost of capital matters for several utilities at the same time would, presumably, allow the Board to deal with the issues more expeditiously as it would not have to be dealing with evidence filed at different times, and in different proceedings, when ensuring that the issues are addressed in a consistent manner.

- *Future Cost Savings.* Should a generic proceeding result in Board decisions on cost of capital that last over a period of years, then Calgary would expect that future cost savings would be achieved either through simplification of future GRA's, or through facilitation of negotiated settlements by removing the cost of capital issue from negotiations.

Statutory Provisions

Calgary believes that the Board has the required jurisdiction to convene a generic cost of capital proceeding pursuant to the provisions of the AEUB Act (ss. 13 and 15); the PUB Act (ss. 36, 37, 46, 47, 89 and 90); the GUA (ss. 22, 36, and 37); and the EUA (ss. 47, 49, and 52).

Consultation Process

As discussed above, Calgary does not believe that the utilities under the Board's jurisdiction have shown any interest in the past in a generic approach to cost of capital issues. As a result, and considering the number of utilities potentially involved, Calgary concluded that the best way to address this issue was through an application to the Board that would allow all interested parties to express their views. Calgary has, however, held informal discussions with some intervenor groups and believes that customer groups, who ultimately bear the burden of cost of capital litigation, will be supportive of any approach that has the potential to reduce costs.

Summary of Relief Requested

Calgary requests that the Board institute a proceeding to determine:

1. the appropriate rate of return on common equity for each utility examined,

2. the appropriate capital structure for each utility examined,

3. the time frame over which the rate of return on common equity should apply,

4. if the time frame for the rate of return on common equity is to be more and one year, or other specified test period, the mechanism by which the rate of return would be adjusted in further years,

5. the time frame over which capital structure should apply, and the process for adjusting capital structure,

6. the appropriate regulatory process for future proceedings dealing with return on equity and capital structure.

Communications

All communications with respect to this Application can be addressed to the undersigned.

Service

Calgary will be providing a copy of this Application to the Interested Party lists from the ATCO Gas South and ATCO Pipelines South GRA's, GCRR Methodology Proceeding, the 2001/2002 TFO Proceeding, and the TransAlta/Altalink Proceeding. Copies will be provided to any other party, or list, that the Board directs.

Yours truly,

Burnet, Duckworth & Palmer LLP

(Original signed by R. Bruce Brander)

R. Bruce Brander

RBB\dk
cc: Interested Parties Lists:
ATCO Gas South 2001/2002 GRA
ATCO Pipelines South 2001/2002 GRA
GCRR Methodology Proceeding
2001/2002 TFO Proceeding
TransAlta/Altalink Proeeding
G:\050343\0135\AEUB Capital Cost Application from Calgary May 6 2002.doc

EUB Alberta Energy and Utilities Board
Calgary Office 640 – 5 Avenue SW Calgary, Alberta Canada T2P 3G4 Tel 403 297-8311 Fax 403 297-7336

Via Email and Mail

File No.: 5681-1

June 6, 2002

Mr. R. Bruce Brander
Burnet, Duckworth & Palmer LLP
Law Firm
1400, 350 - 7 AVE SW
CALGARY AB T2P 3N9

Dear Mr. Brander:

APPLICATION 1271597
COST OF CAPITAL FOR ELECTRIC AND GAS UTILITIES UNDER THE BOARD'S JURISDICTION

I refer to your letter of May 6, 2002, on behalf of the City of Calgary, requesting that the Board convene a proceeding or inquiry to establish a mechanism for determining the cost of capital for utilities under the Board's jurisdiction.

The Board has now had the opportunity to thoroughly review this request. Upon reflection, the Board considers that it would be appropriate to await the National Energy Board's upcoming decision on rate of return before proceeding to deal with this issue.

We will be contacting interested parties further with respect to procedure once this decision has been released.

Yours truly,

<original signed by>

Robert D. Heggie
Executive Manager
Utilities Branch

pc: Interested Parties Lists via Email Only:
- ATCO Gas South 2001/2002 GRA
- ATCO Pipelines South 2001/2002 GRA
- GCRR Methodology Proceeding
- 2001/2002 TFO Proceeding
- TransAlta/AltaLink Proceeding
- EAL Congestion Management Proceeding

Ontario Energy Board **Commission de l'Énergie de l'Ontario**

Ontario

EB-2006-0501

IN THE MATTER OF AN APPLICATION BY

HYDRO ONE NETWORKS INC.

FOR 2007 AND 2008 ELECTRICITY TRANSMISSION REVENUE REQUIREMENTS

DECISION WITH REASONS

August 16, 2007

Summary of the Decision with Reasons
(EB-2006-0501)

Chapter	Application	Board Decision
2	Revenue Requirement Adjustment Mechanism for 2009 and 2010	Not approved.
3	Board's jurisdiction to provide guidance on human resource costs	Board has the authority to make findings and provide guidance on the reasonableness of compensation costs.
4	OM&A expenses	Approved. Data on asset condition to be improved.
	Compensation levels	Approved. Improved reporting required and any reductions in executive compensation to be tracked.
5	Capital expenditure budget	Approved. Data on asset condition to be improved.
	Prudence of Niagara Reinforcement Project	Approved.
6	Special treatment for designated capital projects	Not approved.
	Special treatment of Niagara Reinforcement Project	Applicant allowed to expense carrying costs.
7	Return on Equity	Not approved. Applicant to use the Distribution ROE formula.
	Capital Structure	Same as allowed for electricity distributors.
8	OEB Costs deferral account	Not approved.
	2006 Earnings Sharing Mechanism	Adjustments required to excess income calculation. Capital contribution treatment not allowed.
	2007 Revenue Deficiency Deferral Account	To be effective January 1, 2007.
9	Load forecast	Weather-normal peak load forecast approved. Report required on weather normalization and differences with the IESO forecast.
	CDM impact	Reduced by 350 MW.
10	Charge determinants	Status quo approved.
11	Implementation	Uniform Ontario Transmission Rates to be set in a further proceeding; targeted effective date of change November 1, 2007.

This summary excludes the particulars in the Settlement Proposal and does not form part of the Decision nor does it itemize all findings. It is not to be relied on for the purpose of applying or interpreting the Decision.

TABLE OF CONTENTS

EB-2006-0501

IN THE MATTER OF the *Ontario Energy Board Act,1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the transmission of electricity commencing January 1, 2007.

BEFORE: Pamela Nowina
Vice Chair and Presiding Member

Paul Sommerville
Member

Bill Rupert
Member

DECISION WITH REASONS

August 16, 2007

1. INTRODUCTION

1.1 THE APPLICATION

Hydro One Networks Inc. ("Hydro One", the "Company", the "Utility" or the "Applicant") filed an application dated September 12, 2006 (the "original Application") with the Ontario Energy Board (the "Board") under section 78 of the *Ontario Energy Board Act, 1998*; S.O. c.15, (Sched. B) (the "Act"), for an order or orders approving "the revenue requirement for the test years 2007 and 2008; customer rates for the transmission of electricity to be implemented on May 1, 2007; changes to the current capital structure with an increase in the return on common equity; the inclusion into rate base of certain capital costs; a revenue requirement adjustment mechanism for 2009 and 2010"; and other matters related to the fixing of just and reasonable rates for the transmission of electricity. The Board assigned file number EB-2006-0501 to the Application. Updates to certain parts of the original Application were filed on February 23, 2007 (the "updated Application").

The transmission revenue requirement of Hydro One Networks Inc. (then known as Ontario Hydro Networks Company Inc.) was last set in proceeding RP-1998-0001 when the Board approved a Transitional Rate Order, dated March 31, 1999 and effective April 1, 1999. This revenue requirement was amended to update Hydro One's Rate of Return on Common Equity on March 1, 2000 (EB-1999-0526). On May 26, 2000 the Board issued its decision on Hydro One's transmission cost allocation and rate design application (RP-1999-0044).

Appendix 1 contains details regarding the procedural aspects of the Application, including a list of witnesses and a list of active parties.

1.2 THE SETTLEMENT CONFERENCE AND SETTLEMENT PROPOSAL

An Issues List was provided to parties with Procedural Order No. 2 on December 20, 2006. On March 26, 2007 a Settlement Conference was held to settle as many of the issues as possible. The Settlement Conference resulted in a Settlement Proposal which was filed with the Board on April 3, 2007. The Board considered the Settlement Proposal at a hearing held on April 10, 2007. The Board issued its Settlement Proposal Decision on April 18, 2007. The Settlement Proposal and the Settlement Proposal Decision are attached to this decision as Appendices 2 and 3 respectively.

Of the 40 issues on the Issues List, the Settlement Proposal fully settled 24 issues (the "Settled Issues") and partially settled two issues ("Partially Settled Issues"). The parties were unable to reach agreement on the remaining 14 issues.

Fully Settled Issues

Issue 1.1	Effectiveness and Efficiency of Affiliate Service Agreements
Issue 1.2	Board directions from previous proceedings (some specifics to be addressed part of other issues, principally issues, 9.1, 3.4 and 2.2).
Issue 1.6	Economic and Business Planning Assumptions
Issue 2.3	Cost Allocation between Distribution and Transmission
Issue 2.4	Depreciation Expense
Issue 2.5	Overhead Capitalization Rate
Issue 2.6	Capital and Property Taxes
Issue 2.7	Income Taxes and Methodology
Issue 3.3	Capital and Common Asset Allocation
Issue 3.5	Lead Lag Study for Working Capital Calculation
Issue 3.6	Asset Condition Assessment
Issue 3.7	Allowance for Funds Used During Construction
Issue 5.1	External Revenues
Issue 6.1	Cost Pools and Allocation to the pools
Issue 6.2	Dual Function Lines
Issue 6.3	Wholesale Meter Pool
Issue 6.4	Directly Connected Customers and Line Connection Charges
Issue 6.5	Cost Pools and Local Loop allocation
Issue 7.2	Forecast for Charge Determinants
Issue 7.4	Continuation of the Export Transmission Tariff
Issue 8.1	Deferral and Variance Accounts (establishment and methodology)
Issue 8.2	Deferral and Variance Accounts (amounts and disposition)

Issue 8.3 Service Levels and Performance Standards
Issue 8.4 Demonstration of Need for Leaside/Birch Junction project

Partially Settled Issues

Issue 3.1 Rate Base
Issue 7.3 Charge Determinants for Network and Connection Service

Settlement Proposal Decision

The Board accepted the Settlement Proposal on April 10, 2007 save for the three issues below, which were addressed in its Settlement Proposal Decision of April 18, 2007:

Issue 7.4 The Board modified the language for the settlement of the Export Transmission Rates issue.

Issue 8.4 The Board did not accept the Settlement Proposal and directed Hydro One to present evidence on the need to relieve loading on the connection lines between Leaside TS and Birch Junction TS in the oral hearing.

Issues 8.1 & 8.2 The settlement of the Ontario Energy Board Cost Account was not accepted by the Board.

This Decision with Reasons addresses the 14 non-settled issues, beginning at Chapter 2.

1.3 PARTIAL DECISION AND ORDER

In a letter dated February 14, 2007 Hydro One requested that a 2007 revenue deficiency deferral account be established, beginning January 1, 2007, to record the revenue deficiency between the approved revenue for 2007 and the forecast revenues at currently approved transmission rates. Hydro One requested a decision from the Board on this issue by March 31, 2007. On March 30, 2007, the Board issued a Partial Decision and Order approving the establishment of the 2007 revenue deficiency deferral account. The Partial Decision and Order is attached as Appendix 4. Further details regarding this account are found in Chapter 8 of this decision.

1.4 UNIFORM TRANSMISSION RATES

In this decision, the Board is approving the revenue requirements and charge determinants for Hydro One Transmission which will form the basis for the Hydro One Networks' portion of the Ontario Uniform Transmission Rates. The Ontario Uniform Transmission Rates and the revenue shares of each of the other transmitters in the transmission rates pool (Great Lakes Power Inc., Five Nations Energy Inc., and Canadian Niagara Power Inc.) will be established in a subsequent proceeding.

1.5 THE HEARING, SUBMISSIONS AND EXHIBITS

The hearing took place at the Board hearing room in Toronto on April 23, 24, 26 and May 7, 8, 11, 14, 15, 17, 18, 22, 28 and June 13, 2007. Copies of the evidence, exhibits, arguments, and transcripts of the proceeding are available for review at the Board's offices.

2. PROPOSED REVENUE REQUIREMENT ADJUSTMENT MECHANISM

Hydro One's Proposal

In addition to an order from the Board approving the revenue requirement for test years 2007 and 2008, Hydro One sought approval for a Revenue Requirement Adjustment Mechanism (RRAM) to set transmission revenues for 2009 and 2010 and to replace a full cost-of-service proceeding for those years.

Hydro One described its RRAM for 2009 and 2010 as an indexed revenue requirement plan that is an extension of the 2008 rate setting process. Each of the components of the company's revenue requirement for 2009 and 2010 – operating, maintenance and administration (OM&A) expenses; depreciation; capital taxes; income taxes; and return on capital – would be recomputed prior to each year and submitted to the Board for approval. The Company submitted that its RRAM process would require a much smaller commitment of resources, time and cost than would a full cost-of-service proceeding.

The most significant aspects of the proposed RRAM are the mechanisms used to compute OM&A expenses and the capital expenditures to be included in rate base. Hydro One's approach to these items (set out in its prefiled evidence, and modified by the testimony of its witnesses) is summarized in Table 1. The table deals only with the 2009 calculations but similar calculations would be done for 2010.

Hydro One proposed that the return on capital in 2009 and 2010 would be based upon the debt-equity ratio and cost of debt approved for 2008. The allowed return on equity would be calculated using the OEB-approved return on equity (ROE) formula for 2008, updated for the then current long Canada bond yield. Depreciation expense and taxes for 2009 and 2010 would be simple recalculations based on the updated expense, rate base, and return on capital.

Table 1: Calculation of 2009 Revenue Requirement/Rate Base Amounts Under Proposed RRAM

Expense/capital addition	Calculation of 2009 Amounts
OM&A expenses	(2008 approved OM&A) multiplied by (1 + inflation factor – productivity factor + “OM&A asset aging” adjustment factor)
Sustaining, Operations, and Shared Services capital expenditures added to rate base	(2008 approved Sustaining, Operations, and Shared Services capital expenditures) multiplied by (1 + inflation factor – productivity factor + “capital asset aging” adjustment factor)
Non-IPSP Development capital expenditures added to rate base	Forecast capital expenditures on projects expected to be in service in 2009 *
IPSP Development capital expenditures added to rate base	Forecast capital expenditures on projects expected to be in service in 2009 *
“Supply mix” capital expenditures added to rate base	Forecast capital expenditures expected to be incurred in 2009 (without regard to the in-service dates of the assets) *

**The amounts added to rate base would be subject to a half-year rule.*

Hydro One submitted that the review and approval process for an adjusted revenue requirement for 2009 could commence in June 2008 and could involve at least two rounds of interrogatories and workshops with intervenors. A negotiated settlement would be presented to the Board for approval. While intervenors strongly opposed the proposal, Hydro One said it believes such a process is achievable based on the experience of the British Columbia Utilities Commission, which has used a similar approach in regulating FortisBC .

Dr. Poray of Hydro One stated that the Company was not seeking to have all the details of its proposed plan approved by the Board in this proceeding. Hydro One, he said, would be “willing to work with the intervenors to try and sort out the details, but I think Hydro One would like the assurance of having a concept approved by the Board as a mechanism for moving forward, where the details would be subject to a review, but it would be a review which is much more streamlined than a full cost of service." [1] During his examination-in-chief, Dr. Poray listed the specific approvals that Hydro One was requesting as part of this proceeding:

> First of all, we want the Board to approve the concept behind the revenue adjustment mechanism, that is to say the mechanical adjustment mechanism that uses inflation, productivity and asset-aging adjustment factors to calculate the respective increments in OM&A and capital cost components for 2009 and 2010, starting from Board-approved values.
>
> Secondly, we want the Board to approve the concept behind the derivation of the asset-aging factors, which is based on Board-approved information that Hydro One filed as part of the current proceeding.
>
> Thirdly, we want the Board to approve the setting of a constant productivity factor at one percent for the 2009 and 2010 period.
>
> Fourth, we would want the Board to approve the treatment of capital development costs as we've outlined previously."[2]

Hydro One was clear that its RRAM proposal is not a comprehensive incentive regulation plan. In its pre-filed evidence, the Company noted:

> It will not be realistic to design an effective comprehensive incentive regulation regime before that time [2010] for a number of reasons. Most importantly, the industry is currently going through a period of significant uncertainty. This includes structural changes for the industry as well as uncertainty related to supply mix options and timing. Stability will not be achieved until the OPA's IPSP [Ontario Power Authority's Integrated Power System Plan] is filed and approved by the OEB and until significant progress is made in implementation planning. In addition, it will be necessary to collect appropriate cost data for several years so that cost functions can be estimated as a basis for setting the cost and

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[1] Tr. Vol. 6, p.36

[2] Tr. Vol. 5, p.107 (Dr. Poray is referring to a previous discussion recorded in Volume 5 of the transcript, pages 92 to 99, where he outlines the treatment of capital expenditures in the proposed adjustment mechanism.)

quality parameters for the incentive regulation model that is ultimately adopted as was the case in other jurisdictions[3].

The principal argument made by Hydro One for its RRAM proposal is that it will streamline the approval process during two years that Hydro One expects to have a heavy workload in connection with its capital programs and asset sustainment activities.[4] Other reasons cited by Hydro One were:

- The base year for the adjustment mechanism, 2008, will have been subject to a full cost-of-service review.

- The costs borne by customers for additional operating and capital spending on Hydro One's aging infrastructure will be limited by the pre-approved OM&A and capital adjustment mechanisms.

- The two-year RRAM period will be followed by a full cost-of-service review.

- The two-year RRAM period will allow Hydro One to align subsequent transmission and distribution rate filings.

- The RRAM will reduce the uncertainty with respect to the cost borne by transmission customers in 2009 and 2010, while providing an incentive for Hydro One to contain cost within the envelope established by the adjustment mechanism.

- The RRAM may serve as a first step towards a more comprehensive incentive regulation plan as part of Hydro One's cost-of-service filings for post-2010 rates[5].

[3]Ex.A/Tab13/Sch.1/p.9

[4]Tr. Vol. 5, p. 111

[5] Ex.A/Tab13/Sch1/pp.2-3.

Intervenor Arguments

The RRAM proposal was severely criticized by each of the five consumer groups that participated in the hearing (Association of Major Power Consumers in Ontario "AMPCO"; Consumers' Council of Canada "CCC"; Energy Probe; Schools Energy Coalition "SEC"; and Vulnerable Energy Consumers' Coalition "VECC"). No other intervenors dealt with the RRAM proposal in their arguments. The five consumer groups submitted that the Board should reject Hydro One's proposal and, instead, should require Hydro One to file a full cost-of-service application in respect of 2009 and 2010.

In summary, the intervenors argued that:

- RRAM is only a concept; one that Hydro One acknowledges requires further definition and stakeholdering. The Board should not consider approving an ill-defined proposal.

- It is premature for the Board to approve any automatic revenue requirement adjustment mechanism given the significant uncertainties about the nature and extent of Hydro One's future costs and activities. It was submitted that automatic rate adjustment mechanisms work best when a utility operates in a relatively steady-state environment, which Hydro One admits is not the case today in its transmission business. Some intervenors also submitted that a period of instability and uncertainty is precisely the time when regulatory oversight should be maintained, not relaxed.

- The proposed method of calculating revenue requirement adjustments is flawed. Intervenors raised several issues but were especially critical of the proposed use, and method of calculation, of the OM&A and capital asset aging factors. Intervenors noted that the proposed aging factors were the result of a simple calculation based on the change in spending between 2003 and 2008; no evidence was provided to link the change in spending with asset aging. They also noted that the proposed productivity factor was developed by Hydro One and is not based on external benchmarks.

Board Findings

The Board has been supportive of regulatory mechanisms that provide greater regulatory predictability, reduce regulatory burden, and offer appropriate incentives to regulated utilities. This is clearly demonstrated by the Board's multi-year rate-setting plan for electricity distributors and its current initiative on multi-year incentive regulation for natural gas utilities.

A multi-year revenue requirement adjustment mechanism for electricity transmission may ultimately be appropriate for Hydro One; however, the Board cannot accept the RRAM proposed by Hydro One.

This proceeding is the first cost-of-service review of Hydro One's transmission revenue requirement since 2000. Hydro One pointed out on many occasions that its transmission business today is facing significant change in its spending levels and work programs. During the hearing, Hydro One stressed what it described as an unprecedented increase in capital expenditures driven by government directives and system growth. Hydro One's evidence and its witnesses also referred at length to the significant increase in spending related to Hydro One's aging asset base. The Board also heard evidence about the possible impact of the OPA's IPSP, which has not yet been filed with the Board, on Hydro One's investment plans and spending.

Given these significant changes and uncertainties, the Board does not believe that this is the time to adopt a revenue requirement adjustment mechanism for 2009 and 2010. Before setting the post-2008 revenue requirement, it will be important to examine how actual OM&A expenses and capital expenditures in 2007 and 2008 compare with Hydro One's forecasts (and to determine the reasons for any significant variations), and to test forecasts of spending in subsequent years. That can only be accomplished through a cost-of-service proceeding.

Even if the environment were more stable, the Board would be unable to accept the proposed RRAM because it is not a fully developed plan. The Board does not see how it could approve a mechanism in concept when many of the elements of the mechanism are not clearly defined or are open to change based on future consultations. While the Board appreciates that Hydro One is willing to consult with stakeholders on various aspects of its proposal, it believes that consultation should occur prior to a proposal being submitted to the Board in a rates case.

The Board also shares the intervenors' concerns about some aspects of the proposed indexing of OM&A and certain capital expenditures, especially the use and calculation of the proposed asset aging factors. In its evidence, Hydro One stated that the residual growth in OM&A spending from 2003 to 2008 was "deemed to represent the effect of asset aging on OM&A costs."[6] Should Hydro One choose to submit a multi-year adjustment mechanism that contains asset aging factors as part of its next transmission rates case, the Board will expect detailed evidence to establish that such factors are appropriate estimates of the increase in costs due to asset aging. The Board also expects that any productivity factors will be supported by detailed information and external comparisons.

The Board does not accept Hydro One's proposed Revenue Requirement Adjustment Mechanism for 2009 and 2010. The revenue requirement for those years should be established through a full cost-of-service proceeding. Multi-year incentive regulation for Hydro One Transmission could be implemented in subsequent years.

[6] Ex.A/Tab13/Sch1/p.14

3. JURISDICTION

The Society of Energy Professionals (the "Society") has challenged the Board's jurisdiction to provide detailed guidance to Hydro One with respect to compensation costs negotiated as part of the collective bargaining process with its various unions. In its written submissions it stated:

> It is the position of the Society that the statutory jurisdiction of the Ontario Energy Board to set rates for the transmission of electricity does not include the jurisdiction to:
>
> 1. Issue directions or orders which would in effect require Hydro One to violate the terms of a binding collective agreement with any of the unions representing Hydro One employees;
> 2. Issue directions or orders regarding positions Hydro One must take or objectives it must pursue in collective bargaining with unions representing Hydro One employees;
> 3. Issue directions or orders which in any other way would have the effect of pre-empting free and good faith collective bargaining between Hydro One and the unions representing Hydro One employees.

The Board notes that the Society did not challenge a specific decision of the Board. Rather, the Society appears to be anticipating reasons from the Board similar to those issued in Hydro One's 2006 Distribution Rates Decision (RP-2005-0020/EB-2005-0378), the "Distribution decision"; in particular, certain paragraphs which state clearly the Board's concerns with the Company's labour rates and compensation costs. In its Distribution decision the Board said:

> 3.4.3 The Board notes that the high compensation issue for Hydro One has a considerable history before this Board, dating back to the Ontario Hydro days.

> The Board has noted in this proceeding that since the de-merger of Ontario Hydro, Hydro One has taken a number of steps to control its overall compensation costs by, for example, instituting a voluntary retirement program, outsourcing, use of the PWU hiring hall, initiating various cost efficiency programs, holding the line on compensation increases for management employees and imposing a two-tiered pension structure or a pension plan that is less generous for new employees represented by the Society of Energy Professionals. These are positive steps and the Board expects the company to continue and enhance such efforts in the future and report to the Board at the next main rates case. The Board is particularly concerned about the apparently high labour rates. In this respect, the Board expects Hydro One to identify what steps the company has taken or will take to reduce labour rates.
>
> 3.4.4 Even so, the comparisons between Hydro One's cash compensation with certain other utilities presented by intervenors are of concern. For example, SEC calculated that by applying Ottawa Hydro's compensation costs to Hydro One employees there would a reduction of about $85 million in Hydro One's cash compensation. The Board recognizes that there may be some roughness in the derivation of that figure and some differences in the profile of the two utilities. However the contrast between the compensation structures is of concern to the Board.
>
> 3.4.5 The Board will not make an adjustment to the proposed OM&A costs based on compensation levels at this time but expects the utility to demonstrate in the future that lower compensation costs per employee have been achieved or demonstrate concrete initiatives whereby compensation costs will be brought more in line with other utilities.

In the Society's view, such directions are beyond the jurisdiction of this Board as they interfere with and have the effect of frustrating the statutorily mandated collective bargaining process at the utility.

The Society also contended that in so far as the Board appears to mandate reductions in labour rates or compensation costs, it has assumed a direct role in the negotiation process which is improper and inconsistent with the collective bargaining process. It suggests that in such circumstances, the Board has become "the ghost at the bargaining table" imposing limits on the scope of negotiation without any direct accountability to others participating in the process.

While it appears to find the Board's comments in the Distribution decision to be problematic, the Society did not seek a review of that decision, either at the Board or elsewhere. A consideration of jurisdictional issues is best undertaken when a specific action or decision by the tribunal is considered by a party to fall outside its jurisdiction. Dealing with jurisdictional issues on a speculative or theoretical basis is awkward, and not particularly useful.

If the Society regards some aspects of this Decision to be outside the Board's jurisdiction, it has a range of remedies available to it where its concerns can be addressed and adjudicated. Nonetheless, it may be helpful and appropriate to address some of the issues raised by the Society now.

The scope of the Board's jurisdiction is always subject to its own assessment in light of specific challenges, and, ultimately, when invoked by a party, to that of the Court.

The Board's jurisdiction with respect to ratemaking has been the subject of considerable recent examination by the Board itself and by the courts. While most of that commentary has concerned the process for establishing gas distribution rates, it is clear that the Legislature has endowed the Board with broad powers in the establishment of just and reasonable rates for electricity transmission as well. The Board's jurisdiction derives from the following sections of the Act:

> 19(1) The Board has in all matters within its jurisdiction authority to hear and determine all questions of law and fact.
>
> 19(6) The Board has exclusive jurisdiction in all cases and in respect of all matters in which jurisdiction is conferred on it by this or any other Act.
>
> 78(1) No transmitter shall charge for the transmission of electricity except in accordance with an order of the Board, which is not bound by the terms of any contract.
>
> 78(3) The Board may make orders approving or fixing just and reasonable rates for the transmitting or distributing of electricity and for the retailing of electricity in

> order to meet a distributor's obligations under section 29 of the *Electricity Act, 1998*.
>
> 78(7) Upon an application for an order approving or fixing rates, the Board may, if it is not satisfied that the rates applied for are just and reasonable, fix such other rates as it finds to be just and reasonable.
>
> 78(8) Subject to subsection (9), in an application made under this section, the burden of proof is on the applicant.
>
> 78(9) If the Board of its own motion, or upon the request of the Minister, commences a proceeding to determine whether any of the rates that the Board may approve or fix under this section are just and reasonable, the Board shall make an order under subsection (3) and the burden of establishing that the rates are just and reasonable is on the transmitter or distributor, as the case may be.
>
> 128(1) In the event of conflict between this Act and any other general or special Act, this Act prevails.

In addition, when carrying out its responsibilities under the Act, the Board is subject to explicit objectives to protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service; to promote economic efficiency and cost effectiveness in the transmission of electricity; and to facilitate the maintenance of a financially viable electricity industry.

In assessing the Society's assertions it is important to note that where there is jurisdiction to regulate there is also an obligation to regulate. A regulatory body such as the Board has a positive obligation to fulfill the mandate bestowed upon it by the Legislature.

The Board has a positive obligation pursuant to section 78 to ensure that the rates governing the transmission of electricity are just and reasonable. In a decision that has been relied upon and cited numerous times, the Supreme Court of Canada has held that just and reasonable rates are those which strike an appropriate balance between the interests of consumers on one hand, and the right of the utility to make a reasonable return on its investment, on the other.[7]

A number of intervenors argued, and Board staff observed, that the Board's method of determining just and reasonable rates does not include prohibiting the subject utility from making expenditures or incurring costs at rigidly prescribed levels. Rather, the Board approves a revenue requirement that is consistent with its findings on various cost categories, including operating costs. The courts have recognized that operating costs include compensation costs[8], and that in the course of setting just and reasonable rates, numerous costs may be subject to challenge including those related to compensation plans[9].

The Board's obligation to arrive at just and reasonable rates, and to protect the interests of consumers, requires it to assess the reasonableness of all cost categories for which recovery is sought. The Board has a wide discretion to allow, disallow or adjust the components of both rate base and expense[10].

In the Distribution decision, the Utility's labour rates and compensation costs appeared consistently higher than those of comparable North American utilities. As a result, the Board panel deciding the Distribution case asked the Utility to identify steps it had taken or would take to reduce labour rates in the next Distribution rates case filing. The panel also required the Utility "to demonstrate in the future that lower compensation costs per employee have been achieved or demonstrate concrete initiatives whereby compensation costs will be brought more in line with other utilities".

[7] "Just and reasonable" rates have been defined by the courts as those which are fair to the consumer and which permit the company to earn a fair return on the capital invested: *Northwestern Utilities, Ltd.* v. *City of Edmonton et al*., [1929] S.C.R. 186, cited in *Re Union Gas Ltd.* v. *Ontario Energy Board et al*. (1983) 1 D.L.R. (4th) 698 (Ont. H.C.J.), p. 706.

[8] *Re Union Gas Ltd. v. Ontario Energy Board et. al*., ibid., p. 702.

[9] *Transcanada Pipelines Ltd*. v. *Canada (National Energy Board)* [2004] F.C.J. No. 654. (C.A.), para. 34.

[10] *Re Union Gas Ltd. v. Ontario Energy Board et al*., *supra.*, p. 712.

That panel also required the Utility to provide further detailed information respecting the full extent of what appeared to be a disparity in comparative compensation costs. The underlying rationale for this finding was to ensure that the costs incurred by the Utility with respect to labour rates and compensation costs are reasonable, and can therefore form the basis of part of the overall revenue requirement of the Utility.

The same approach is taken for all other categories of costs that comprise a utility's revenue requirement. In making the finding that it did in the Distribution case, the Board was giving the Utility fair warning that the Board had concerns about the apparent disparity in comparative labour rates and compensation costs.

The Board did not and does not prohibit the Utility from paying to its workforce whatever it negotiates within the context of its labour relations environment. What the Board does do is limit the recovery as part of the revenue requirement to that portion of compensation cost which the Board finds to be reasonable.

In other words, the Utility is free within the negotiating environment to arrive at whatever resolution it sees fit. It has to do so, however, with knowledge that full recovery of the consequential cost may not be available to the extent that the Board considers the settlement to be unreasonable.

To do otherwise would make the ratepayers captive to whatever private arrangements are agreed to by the Utility and its unions. The Board can only meet its responsibility to protect the interests of consumers if it assesses the reasonableness of the costs which result from such settlements and provides for recovery according to a fair, transparent, and principled regulatory approach.

In its Reply submission, the Society argued that the Board has no authority to make orders which have the effect of compelling the Utility to violate labour relations agreements to which it is bound.

It is not the practice of this Board to make any such orders. The Board is expressly not bound by the terms of any contract in its establishment of just and reasonable rates pursuant to Section 78 of the Act. The Board assesses the reasonableness of the cost consequences of the utility's arrangements, and establishes the revenue requirement on the basis of that assessment. The Board's view of the reasonableness of compensation costs is just one of the factors that the parties at the bargaining table must take into account. The consequence of a Board finding that this category of cost is excessive is a possible disallowance of a portion of the amount claimed by the utility for inclusion in the revenue requirement. In that hypothetical case, the utility would decide whether to attempt to change its compensation practices or to source the additional funding from the shareholder.

Accordingly, the Board finds that it has the authority to make findings and to provide guidance with respect to the reasonableness of a utility's compensation costs for the purpose of setting just and reasonable rates for utility service.

4. OPERATIONS, MAINTENANCE AND ADMINISTRATION

This chapter contains the Board's findings on Hydro One's proposed Operations, Maintenance and Administration expenses (OM&A) as well as the level of the Company's compensation costs.

4.1 OM&A EXPENSES

Hydro One's updated evidence showed a forecast for OM&A expenses of $394.1 million for the 2007 test year with a slight decrease to $387.5 million in the 2008 test year. The 5.1% increase for 2007 was in addition to an increase of almost 10% in the 2006 bridge year. Table 2 shows Hydro One's forecast amounts compared with those in the preceding four years.

Table 2: OM&A Expenses 2003 – 2008

	Historic			*Bridge*	*Test*	
$ millions	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
OM&A by category						
Sustaining	$146.9	$153.9	$166.3	$179.0	$200.1	$200.9
Development	2.2	5.0	6.7	8.1	8.0	8.1
Operations	36.6	49.5	38.3	42.9	45.8	46.2
Shared services and other	125.8	81.9	59.9	76.3	67.4	57.1
Taxes, other than income taxes	55.4	68.1	70.5	68.6	72.8	75.1
Total OM&A	$366.8	$358.4	$341.8	$374.8	$394.1	$387.5
Year over year % change						
Sustaining OM&A		4.8%	8.1%	7.6%	11.8%	0.4%
Total OM&A		-2.3%	-4.6%	9.7%	5.1%	-1.7%

This part of the hearing focused mainly on Sustaining OM&A expenditures as this category represents just over half of the OM&A total. The Sustaining OM&A budget represents spending required to maintain existing transmission lines and station facilities so they will continue to function as originally designed and meet overall system reliability, environmental and safety requirements.

One reason for intervenor interest in the Sustaining category is the fact that it has had consistent increases in expenditures from 2003 through to the test years. Sustaining spending in 2007 is forecast to be almost 12% higher than in 2006, a year in which spending rose by 7.6% over 2005 levels.

Hydro One defended its Sustaining OM&A expenditure plans on the basis of its business planning process where it uses leading measures related to the performance, condition and age of the specific assets which make up the transmission system. The information supporting Hydro One's plans include asset performance (asset failure rate) studies, asset condition assessments and asset demographics information.

The asset demographic information identified the number of assets which are expected to enter specific critical age regions, such as mid-life, where incremental maintenance requirements are necessary to ensure continued asset performance, and end-of-life where it becomes uneconomic to try to sustain the required performance levels. Hydro One emphasized that both the volume and scope of OM&A work is increasing for Hydro One's aging fleet of assets. It is the Company's position that the business planning process utilized by Hydro One has established the appropriate level of sustaining work, based on a detailed needs identification and work program prioritization[11].

VECC highlighted that in Hydro One's original application, Sustaining OM&A expenditures were increasing by 28% from $155.9 million in 2006 to $200.1 million in

[11] Ex.A/Tab14/Sch1

2007. In the evidence update, the Sustaining OM&A spending for 2006 was revised upwards to $179.0 million.

Hydro One's explanation for the higher than expected spending in 2006 was that higher than anticipated failure rates were experienced that year, associated with a specific transformer design and storms. Unexpected difficulty in getting cleanup crews to the affected sites increased unanticipated expenses Hydro One testified that this higher 2006 spending does not impact on spending plans for 2007 and 2008.

VECC did not accept Hydro One's assertion that assets and performance were actually deteriorating. VECC noted that as the updated information provided by Hydro One showed that outages of 230kV circuit breakers were lower in 2006 than in any of the previous three years, and that outages of 230 kV transformers were well below 2005 levels and in line with those in 2003 and 2004.

VECC also argued that the 2006 asset condition assessment did not show a marked difference in overall condition of the transmission assets and did not substantiate the requested increase in OM&A Sustaining spending.

VECC also noted that Hydro One's evidence indicated that a significant portion of the Priority 1 ("very poor") and Priority 2 ("poor") assets will actually be replaced over the 2006-2008 period. VECC submitted that if this level of replacement proceeds, it will have a direct impact on the level of Sustaining OM&A spending needed for these assets and should reduce overall maintenance requirements. VECC also noted that in the High Level Transmission Benchmarking Study prepared by the PA Consulting Group (September 6, 2006), [12] Hydro One Networks OM&A spending was close to the average for those utilities surveyed when normalized on either a total Gross Asset Basis or a MWh transmitted basis using data from 2003-2005. Similarly, Hydro One's reliability was shown to be about average. VECC held that this evidence showed that current levels of spending were reasonably adequate.

[12] Ex.A/Tab15/Sch2

In conclusion, VECC submitted that the proposed Sustaining OM&A budgets be reduced by 6% in both test years to $188.1 million in 2007 and $188.8 million in 2008.

AMPCO questioned whether the evidence established that assets are aging at a specific rate, or a rate greater or lesser than in the past, or that asset aging is creating a significant deterioration in reliability. AMPCO urged the Board to direct Hydro One to provide clear evidence on asset aging at its next rate hearing.

Citing evidence which appeared to show that the 2006 outage performance was better than previously indicated, AMPCO argued that Hydro One's data did not support a claim of significant and increasing problems with asset performance.

AMPCO maintained that Canadian Electrical Association data did not indicate a significant deterioration in system performance over the period 2003 to 2006. In addition, Hydro One's evidence showed that the Company achieved first quartile system performance compared to American utilities over the five-year period from 2000 to 2005.

AMPCO also submitted that the higher proposed capital spending should reduce the need for additional sustainment OM&A spending in future years.

Based on the above, AMPCO submitted that the 2007 Sustaining budget should be reduced to $185 million, and the 2008 budget to $195 million. AMPCO noted that Hydro One's proposals for Development, Operations, Shared Services and Other OM&A appeared reasonable.

CCC supported the AMPCO analysis of asset aging, asset condition and asset performance. CCC was also concerned about the increased bridge year spending revealed in the update, with no reduction shown in 2007 and 2008 plans. CCC recommended Sustaining OM&A spending be reduced by $10 million to $190.1 million in 2007.

SEC also submitted that planned Sustaining OM&A increases were too high in the test years. SEC argued that expenditure increases should have taken place earlier, citing evidence from Hydro One's 1999 transmission rates proceeding which indicated Hydro One was already aware that blocks of assets were reaching the end of their service lives.

SEC argued a prudent company, operating in a competitive market, which foresaw an imminent need to refurbish or replace aging assets would not wait until all of those assets reached a certain age before taking action. Rather, it would seek to smooth the impact of those investments to avoid problems with cash flow in a given year.

SEC also referred to the improvement in asset failure rates and forced outages in 2006, as shown in the updated evidence. SEC focused on Exhibit L1.3 where comparisons of OM&A per line kilometre show a 12% increase from 2006 to 2007 compared to an average annual increase between 2003 and 2006 of only 7%. SEC recommended that the Sustaining OM&A budget should be frozen at the updated 2006 level of $179 million for each of 2007 and 2008. This would mean a reduction in the OM&A budget of $21.1 million in 2007, and $21.9 million in 2008. SEC's rationale for the reduction is based on its view that although planned expenditures in 2007 and 2008 are needed, they are unreasonable for inclusion in 2007 and 2008 rates because they are the result of imprudently low expenditures in the historic years. It contends that the Company should have been investing in the business during a period of overearning, and should not make up for that failure during the test years. SEC also asserts that the proposed spending levels do not take into account the higher 2006 spending levels revealed in the evidence update in February. In its view, this higher spending in 2006 should result in lower spending in the test years.

The Power Workers' Union ("PWU") supported the levels of OM&A spending applied for by Hydro One on the basis that Hydro One demonstrated the need for the levels of spending through their planning methods (asset condition assessment, outage data and asset aging data). PWU argued that if the Board found that these planning methods are reasonable, then the results should be accepted as well. PWU submitted that as more units of work are required, and wages and material costs are increasing also, the increased costs are justified. PWU also submitted that if reductions are ordered, the impact of not doing this work on service quality, reliability and safety must also be taken into account.

Board Findings

Hydro One is seeking approval of a significant increase in its Sustaining OM&A spending. The key issue is the need for planned spending in 2007 which is almost 30% higher than the $155.9 million originally planned for 2006.

The primary concern of intervenors with respect to this increase is its magnitude when compared to spending in this area in the recent past. Hydro One's response was that the need for such increases became apparent recently, and as the result of improved analytical and planning techniques. It argues that it would not have been prudent to make larger investments in preceding years, given its understanding of the condition of its plant at that time.

It is the view of the consumer intervenors that such large program increases require strong and objective evidence of a broadly-based deterioration in system performance or a demonstrated severe and rapid deterioration of a major asset class. They argue that no such evidence has been provided by Hydro One.

Intervenors suggest that it is impossible to conclude from the evidence provided by Hydro One that its asset base is aging at any specific rate, that this rate is greater or less than it has been in the past, or that further asset aging is creating a significant deterioration in reliability. Intervenors also assert that the evidence does not support claims of significant and increasing problems with Hydro One's assets or system performance deterioration.

Hydro One answers that the use of historic data to extrapolate an appropriate spending level for the test year is unsound. It argues that transmission system reliability is a lag indicator – by the time impairments in reliability become apparent it is too late. The Company relies on an improved package of leading indicators to plan its expenditures in this category.

The Company also asserts that while the evidence shows there was a marginal decrease in the failure rate of a single asset class in 2006, the trend is that of increasing and continuing deterioration overall.

The Company also disputes the claim made by some of the intervenors that the 2003/2006 Asset Condition Assessment comparison does not show asset condition deterioration. It suggests that the comparison made by the intervenors is inappropriate, given that it is based on two materially different data bases. The Company also separates its significant increases in capital expenditures to replace assets from its OM&A budget. It argues that there is no good reason to conclude that the replacement program contemplated will have any material effect on the short-term OM&A requirements.

The Board notes that the concerns of the intervenors with respect to the proposed level of spending were heightened by Hydro One's request that the Board approve a RRAM for 2009 and 2010. Under the proposed RRAM, the approved OM&A spending for 2008 would find its way into a rate adjustment mechanism for the following years. As noted in Chapter 2, the Board has not approved Hydro One's request for the RRAM, and the revenue requirement for 2009 will be based on a cost-of-service examination.

In the OM&A section of the Application, as in a number of other sections, the Board found some of the evidentiary record to be inadequate or incomplete. For example and as noted above, the Applicant insisted that the overall trend of its assets was continued and increasing deterioration while the evidence it placed before the Board on that point showed a marginal decrease in the failure of a single asset class in 2006. The Board has concerns about the comparatively low spending levels in the years preceding the bridge year. It would be expected that a large and capable transmission company, such as the Applicant, would have had a more reliable asset condition assessment capability than appears to have been the case until recently. The Board would expect that the Company would attempt to smooth spending on this category of expense as much as possible, given the nature of the activity, which is, by definition, incremental in nature. It is concerning that the revenue requirement would include such a steep increase from one year to the next. While the Company has provided an explanation for its request for the sharp increase sought there remains ambiguity about the real state of the asset base. The evidence presented by the Company is not always consistent with the claims advanced.

It would have been better had the Company had been able to demonstrate with more acuity the statistical and technical underpinning of its point of view. The safe and reliable operation of the system is of paramount importance to the province's economy, and the well being of its population. This Application, and many other matters currently before the Board, documents the fact that the transmitter is engaged in very significant extensions and reinforcements of the system.

In the Board's view, resolving the ambiguity of the asset reliability evidence against the applicant by reducing the proposed OM&A budget would be inappropriate and unsafe. The Board is convinced that the Company has genuinely formed the judgment, based on its engineering expertise and its enhanced analytical capability, that increases of the nature applied for are needed to maintain a robust, safe, and reliable transmission system.

Accordingly, the Board will approve the OM&A budget as applied for the years 2007 and 2008. However, the Board directs the Applicant to work with intervenors to develop the type of and format for data reflecting asset condition. In particular, the Board directs Hydro One to provide asset aging data which includes data by value and importance of the type of asset, as suggested in AMPCO's submissions, in its next transmission rates proceeding.

It is important that an approach is found that will allow all parties to make better assessments of the state of the asset base at the time of the next revenue requirement case. This data must enable the Company to bring to its next cost of service application a reliable representation of all important parameters of the condition and reliability of the asset base and the financial implications thereof. The Applicant will report to the Board no later than six months from the date of this decision on the progress made in the development of its improved asset database. It is the Board's intention that this stakeholdered exercise be implemented in time to provide a very clear representation of the condition of the Company's plant in time for its expected cost of service application for the 2009 revenue requirement.

4.2 EMPLOYEE COMPENSATION

Several intervenors directed their arguments to the overall size and growth of Hydro One's employee compensation cost. These issues are covered in this section. Some intervenors also raised issues with respect to two narrower compensation issues. Those issues are the rate treatment of incentive pay, and the possible impact on senior management compensation of the recommendations of the Province of Ontario's Agency Review Panel. Those two smaller issues are covered at the end of this chapter in section 4.3.

Hydro One conducts both its transmission and distribution businesses within a single corporate entity, Hydro One Networks Inc. Table 3 provides summary information on combined compensation cost and headcount for Hydro One's transmission and distribution businesses for the past four years, and the proposed amounts for 2007 and 2008.

Table 3: Employee Headcount and Compensation (total Hydro One Networks)

Compensation cost in $ millions	Historic			Bridge	Test	
	2003	2004	2005	2006	2007	2008
No. of employees at year end						
Regular	3,696	3,841	3,904	4,018	4,204	4,158
Non-regular	906	1,032	1,174	1,283	1,605	1,645
Total	4,602	4,873	5,078	5,301	5,809	5,803
Compensation cost *	$388.1	$404.2	$397.9	$459.3	$493.0	$508.0

* Includes base salary, overtime pay, incentive pay, benefits (other than costs for pensions and other post-employment benefits), and other compensation.

Source : Exhibit J1.40

A portion of Hydro One's compensation cost is included in OM&A expenses and the balance is included in the cost of various capital projects. Hydro One did not file any information in this proceeding about the amount of total forecast corporate compensation cost for 2007 and 2008 that will be borne by the transmission business (either as OM&A expenses for 2007 and 2008 or as additions to the transmission business rate base). The Company did estimate that just under 50% of full-time equivalent employees for the test year 2008 would be allocated to the transmission business based on the split of work programs between transmission and distribution.

The Board considered compensation issues at Hydro One most recently in its hearing on 2006 rates for the company's distribution business. Given the short interval between the release of the Board's decision on Hydro One's distribution rates in April 2006, and the filing of Hydro One's transmission rates application in September 2006, it is understandable that most of the compensation issues raised by intervenors in this case would be the same as those addressed in the distribution rates case.

In the Distribution decision, the Board made the following observations (in paragraphs 3.4.3 to 3.4.5):

- in future rate cases it expects Hydro One to identify what steps the company has taken or will take to reduce labour rates;

- the contrast between the compensation structures of Hydro One and some other utilities is of concern; and

- in future rate cases it expects Hydro One to demonstrate that lower compensation costs per employee have been achieved or to have concrete initiatives in place to bring compensation costs more in line with other utilities.

Hydro One stated that its approach to compensation has to be considered in light of several environmental factors. First, over 90% of Hydro One's workforce, including its engineers, is unionized, which places significant constraints on its ability to reduce compensation cost per employee. The two largest unions are the PWU and the Society. In the event of a strike by the PWU, which represents 70% of the company's workforce, Hydro One stated that it would be unable to sustain operations. Second, like many other entities in the power sector, Hydro One has an aging workforce, with over 1,000 employees eligible to retire by the end of 2008. The Company said it was working hard to strike a balance between the need to control compensation costs, and the need to hire new workers and to retain existing staff. Third, over the next few years, Hydro One must complete a large work program involving asset sustainment and major development projects.

Despite these factors, Hydro One submitted that it has had some success with its two major unions. It listed five areas in which it believes it has made gains in negotiations with the PWU (such as eliminating incentive pay) and three areas in which it has made gains in negotiations with the Society (including a pension arrangement for new Society employees that is 25% less costly than the pensions for existing employees). The Company also intends to increase its reliance on external consultants and contractors as a way to deal with its major work programs.

Hydro One filed a benchmarking study, prepared by PA Consulting in September 2006 (the “study” [13]), which compared 21 of the Company’s business performance metrics with 13 North American utilities.   It also provided specified wage rate and overtime policy comparisons for three job classifications with 13 Canadian regulated transmission or distribution companies. With regard to the specified wage rate and overtime policy comparisons, Hydro One’s rates were highest for two of the job classifications and third highest for the other.

Hydro One argued that the benchmarking study was completed under tight time constraints on a “best efforts” basis and has several shortcomings which limit its usefulness. The study itself referred to several limitations and noted that further substantial effort and investigation would be required before any conclusions can be drawn. Hydro One stated that given more time it would not necessarily have selected the 13 companies for a benchmarking study on salaries.

PWU supported the forecast compensation costs for 2007 and 2008. It submitted that given the heavily unionized and aging workforce, and Hydro One’s need to complete a major work program over the next few years, the Board should not expect any material reduction in cash compensation per employee. It also argued that the results of the benchmarking study were incomplete and inconclusive, and cautioned the Board against drawing any conclusions from the study’s labour rate comparisons.

The Society argued that compensation costs for Hydro One’s unionized employees are not high. It cited many of the same environmental factors noted by Hydro One as support for this view. It also submitted that total compensation cost per employee is not a useful measure of the Company’s efficiency. Rather, it would be better to assess Hydro One’s performance against productivity measures such as units of

[13] Hydro One was directed by the Board in the Distribution decision to prepare a high level benchmarking study for the next distribution rates case, based on a list of comparable North American companies with similar business models (transmission and/or distribution) and to report on high level comparative performance and costs information for Hydro One and the companies. The Company was directed to submit the study “on a best efforts basis” in its transmission rates application for 2007.

accomplishments per employee.

Although the Society accepts Hydro One's compensation budget, it said that if the Board continues to have concerns there are better ways for Hydro One to increase efficiency than to reduce compensation for unionized employees. It recommends that Hydro One address what the Society considers to be an unnecessarily high manager-to-employee ratio, made worse in 2006 as the result of the transfer of 155 Society-represented positions to management positions.

CCC said it continues to be concerned about the overall level of Hydro One's compensation costs. It did not, however, recommend any reduction in Hydro One's proposed revenue requirement as a result of such concerns. Instead, it urged the Board to direct the Company to work with stakeholders to propose and undertake a meaningful review of costs relative to comparators.

Energy Probe described Hydro One's overall compensation cost as clearly excessive and above market. It acknowledged that the issue requires management's attention over a number of years and said it is difficult to move towards market-based compensation every year. It argued that, as part of Hydro One's next distribution rates case, the Company should be required to provide more responsive evidence on initiatives to achieve cost per employee closer to market value.

SEC submitted that Hydro One's evidence on compensation was not responsive to the Board's direction to the Company in the last distribution rates case. It said the various negotiated gains cited by Hydro One in this application pre-dated the Board's April 2006 decision on distribution rates. It also challenged Hydro One's statement that the elimination of incentive pay for PWU-represented employees was a gain as it appears that the gain was offset by higher base pay.

Despite its concerns, SEC did not recommend any change in the forecast compensation costs except for a component of forecast management compensation. In 2006, Hydro One increased the minimum and maximum pay bands for management employees, an action SEC said was not appropriate because management salaries “set the bar for all the Company’s pay bands.” SEC recommended that the Board disallow the portion of forecast compensation costs resulting from this change without specifying an amount, or if the amount involved is material.

SEC said the Board should reaffirm the direction given in the Distribution decision and warn Hydro One that it will risk not recovering all of its compensation costs if it fails to take reasonable steps to reduce compensation.

VECC and SEC noted that the compensation comparisons provided by Hydro One look only at base salary and short-term incentives. Both intervenors recommended that in future filings Hydro One should provide information on how its total compensation, including pension and similar benefits, compares to other companies. VECC also recommended that Hydro One should develop measures that would allow parties to judge whether the size of the Company’s management group is appropriate.

Board Findings

The Board finds itself in the same position after this hearing as it was after the hearing on Hydro One’s 2006 distribution rates – it has lingering concerns about the size and growth of overall compensation costs at Hydro One. Having said that, the Board will accept the forecast compensation costs for 2007 and 2008. The evidence on compensation costs in this proceeding, while less than optimal, is sufficient to enable the Board to make this finding. While intervenors have expressed concerns about these costs, they have not been able to challenge these amounts convincingly, nor have they provided any coherent basis upon which the costs could be reduced. The Board notes that none of the intervenors recommended any disallowances except for SEC, which advocated that due to widening pay bands, any increases in management compensation should be disallowed.

Some intervenors recommended that the Board should direct Hydro One to prepare a more comprehensive study of its compensation costs and how they compare with the costs of comparable utilities. Hydro One indicated during the hearing that it is carrying out further work now that will be filed as part of its next distribution case.

The Board looks forward to the filing of a study which provides useful and reliable information concerning Hydro One's compensations costs, and how they compare to those of other regulated transmission and/or distribution utilities in North America.

To that end, the Board directs Hydro One to consult with stakeholders about the type of information to be gathered and the types of utilities and other companies that should be used for comparison purposes. The Board also expects Hydro One to gather and compare data reflecting total compensation costs, not just base salaries. Detailed comparisons of compensation costs for specific job categories are of some help in understanding how Hydro One compares to others in the industry. Equally important is the size and trend of labour costs per unit of output of various sustainment, development, and corporate activities. In the study that Hydro One is now preparing, the Board expects it to provide empirical evidence which reveals the relative productivity of its workforce in comparison to other utilities. Deficiencies in the evidence which are not fully justified could be construed against the utility in its next rates case.

The PA study filed in this Application suffered from various deficiencies and shortcomings, as noted by the authors of the study, the Applicant and the intervenors. The Board expects the new study to be comprehensive and reliable, with none of the limitations of the PA study. If Hydro One cannot correct all of these deficiencies in time for the Company's 2008 Distribution rate filing, the Board expects them to be corrected in the 2009 transmission filing.

4.3 OTHER COMPENSATION ISSUES

In its decision on Hydro One's 2006 distribution rates, the Board approved the inclusion of incentive compensation payments in the revenue requirement. The Board also made the following comment:

> While the Board does not consider the achievement of net income to be a factor that works only for the benefit of the shareholder, as customers benefit from a healthy utility through higher credit ratings and good service, the Board would be concerned if this factor predominated compared to the other factors determining incentive pay. The Board expects Hydro One to file appropriate evidence in its next main rates case to establish that none of the incentive compensation should be charged to the shareholder."[14]

Budgeted incentive payments for Hydro One's transmission and distribution businesses are $6.9 million for 2007 and $8.5 million for 2008. Hydro One did not file information that specified the portion of those amounts that relate solely to its transmission business. (As noted in section 3.2 above, Hydro One estimated that just under 50% of its full-time equivalent employees would be allocated to its transmission business.) The amount of incentive payments are linked to 14 performance measures included in the company's balanced scorecard, one of which is the achievement of net income targets.

Although the amounts may not be significant, CCC recommended that as a matter of principle none of the forecast incentive pay for 2007 and 2008 should be recovered through transmission rates. CCC submitted that this would be consistent with the methodology the Board has applied to electricity distributors. Energy Probe accepted that incentive payment targets do benefit ratepayers but argued that 25% of the amounts should be disallowed because Hydro One failed to file evidence that none of the cost should be borne by its shareholder. VECC also recommended a 25% disallowance. SEC recommended the disallowance of an unspecified portion of the forecast payments.

CCC and VECC also recommended that Hydro One be directed to establish a deferral account to track any cost reductions in 2007 and 2008 that result from Hydro One's implementation of the findings of the Agency Review Panel, established in January 2007. It released its Phase I report on executive compensation at Hydro One and four other provincial electricity sector institutions on June 27, 2007. At that time, the Minister

[14] Decision With Reasons, RP-2005-0020/EB-2005-0378, April 12, 2006. para. 3.4.6.

of Energy announced that he has directed each institution to implement the Panel's recommendations.

Board Findings

The Board accepts the inclusion in the revenue requirement of the forecast incentive payments.

The concern of intervenors is the inclusion of a net income target in Hydro One's balanced scorecard, which is the basis for incentive payments. The Board acknowledges that its 2006 Distribution Rate Handbook ("2006 EDR Handbook") stated that incentive payments related to benefits to shareholders would not be recoverable in the 2006 revenue requirement of a distributor. In the Board's view, our decision to allow incentive compensation costs in Hydro One's transmission revenue requirement is not in conflict with the 2006 EDR Handbook. First, net income is only one of 14 performance measures in Hydro One's balanced scorecard; there is no evidence that the net income performance measure predominates, which was the concern expressed by the Board in the Hydro One distribution decision. Indeed, Hydro One pointed out that incentive payments are contingent on meeting a range of performance measures; no payouts would occur if the net income target were met but other measures were not achieved. Second, there is no evidence that would allow the Board to make an objective determination of how much of the forecast incentive payments relate to shareholder benefits. Even if that were possible, it appears to the Board that the amount, if any, would be very small given that the total incentive payments allocated to the transmission business for the test years are not particularly significant.

Executive compensation costs in Hydro One's application obviously could not have reflected the recommendations of Agency Review Panel. The impact of the recommendations on Hydro One's executive compensation for 2007 and 2008 is unknown given that the Company's Board of Directors would only recently have started the implementation process. In addition, the effective date of any new compensation practices at Hydro One is also unknown. Accordingly, there is no way to predict if the impact in 2007 and 2008 of the implementation of the Agency Review recommendations will be significant.

The Board would generally not require a utility to track variances in routine costs when new information about the extent of those costs in the test years becomes known only after the rates hearing is completed and the parties have submitted argument.

In this case, the Board believes an exception is warranted. In his announcement of the release of the Panel's report, the Minister of Energy noted that the government wants to ensure that compensation for top executives strikes an appropriate balance between being competitive on the one hand, and fair to ratepayers, on the other. The Board directs Hydro One to track any reduction in executive pay during 2007 and 2008 that results from implementing the Panel's recommendations and to report that amount at its next transmission rate case.

5. CAPITAL EXPENDITURES

Hydro One's updated evidence shows a significant increase in transmission capital spending. The Company has requested approval for capital expenditures of $691.5 million in the 2007 test year and $768.2 million in 2008, as shown in Table 4. The 2007 amount is 72% higher than bridge year levels and the 2008 amount is 11% higher than 2007. The bridge year amount of $401.6 million was 15% higher than 2005 levels. The two main areas of this growth are the Sustaining and Development capital budgets, which comprise over 90% of the total proposed capital expenditures.

Table 4: Capital Expenditures 2003 – 2008

	Historic			Bridge	Test	
$ millions	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**
Capital Expenditure by Category						
Sustaining	$160.3	$173.7	$168.9	$178.5	$288.1	$295.6
Development	59.5	217.3	134.6	179.4	298.7	409.4
Operations	38.9	20.7	10.2	9.4	20.1	20.4
Shared Services & Othe	28.7	20.2	35.5	34.1	84.6	42.7
Total*	$287.4	$431.9	$349.2	$401.4	$691.5	$768.1
Year over year % change						
Sustaining		8.4%	-2.8%	5.7%	61.4%	2.6%
Development		265.2%	-38.1%	33.3%	66.5%	37.1%
Total Capital Expenditures		50.3%	-19.1%	14.9%	72.3%	11.1%

**Note: Totals may not add due to rounding.*
Source: Exhibit D1/Tab3/Sch1

Hydro One defended its capital budgets on the basis of what it considers a comprehensive planning process that encompasses the effects of an aging asset base, the results of the asset condition assessment and monitoring of failure rates. In addition, its process takes into account significant expansion of the transmission system to accommodate what the Utility describes as the changing electricity infrastructure needs of the province.

Intervenors generally limited their arguments to the Sustaining and Development budgets.

5.1 SUSTAINING

The Sustaining budget is growing from $178.5 million in 2006 to $288.1 million in 2007, an increase of 61% with a further small increase in 2008 of 2.6%.

Sustaining expenditures include the cost of investment required to replace or refurbish components to ensure that existing transmission system facilities function as originally designed. The evidence showed that these capital expenditures are largely driven by the same factors as OM&A spending, that is, asset condition assessment, asset aging records and data respecting failures and outages.

Intervenors' concerns fell largely into three categories: concerns that the asset assessment was not sufficiently robust to accurately determine the need to replace the assets; criticism that Hydro One spent insufficient funds on asset maintenance in previous years; and concerns that Hydro One would not be able to spend all the funds budgeted.

Part of Hydro One's asset analysis relied on information on asset failure rates. VECC argued that updated information on failure rates showed that outages were actually lower than those used to develop the sustaining budget. In addition, VECC argued that the 2006 asset condition assessment was not much different than the previous (2003) assessment. Overall, VECC questioned whether this information justified the large increase in sustaining capital expenditure.

SEC reiterated the arguments it made with respect to the OM&A budget, namely that Hydro One had ample information regarding the state of its asset base during the historic period to justify gradual increases in expenditures so as to avoid major increases in the test years. SEC suggested that this demonstrated that the Sustaining capital budget should be reduced, but did not suggest a specific reduction in the test years.

AMPCO's position was that the evidence on asset aging was not clear, and urged the Board to direct Hydro One to provide better evidence of asset aging at its next rate hearing. AMPCO also questioned the evidence that system performance was deteriorating. In addition, AMPCO cited Hydro One's performance compared to analogous utilities. Further, AMPCO argued that there should be significant sustainment benefits arising from the proposed large increase in development spending, which will result in the replacement or upgrading of existing components in capital projects. AMPCO submitted that the sustainment budget should be reduced to $215 million in 2007 and $255 million in 2008.

Hydro One responded that its capital spending plans are based on multi-year trends in asset failures, and a slight reduction in failures in 2006 would not cause it to alter its plans for single year results or for a single asset group.

Hydro One also argued that the asset condition assessment methodology for 2006 was markedly different than the 2003 study, with a larger asset base, refined techniques, improved data quality and enhanced algorithms. Hence, the results of the two assessments were not directly comparable. Hydro One maintained that the evidence it had in the earlier period, when it completed its business planning, did not justify higher expenditures in the years leading up to the test year. There was no reason to increase expenditures during that period, given that the information available at that time did not show a need to accelerate replacements or upgrades. In addition, Hydro One asserted its evidence points to increasing numbers of mid-life and end-of-life assets, largely the result of a high growth period in the 1950s and 1960s.

PWU supported the Hydro One request for Sustaining capital, citing the asset aging and performance evidence as well as raising the risk to reliability, service quality, safety and increased maintenance costs, if capital spending were to be reduced from planned levels. The PWU stated that some of the increased budget for Sustaining capital was a result of the increasing cost of material and equipment in a time of unprecedented transmission development globally.

Board Findings

The findings in this decision on OM&A expenditures are very relevant to these findings, as increases in both cases are largely based on aging assets. Hydro One is seeking approval of a sustainment capital budget that increases by an extraordinary 61% from 2006 to 2007. Intervenors are understandably concerned. Their concerns regarding asset assessment information are equally relevant to sustainment capital and OM&A.

The Board accepts that Hydro One's asset assessment methodology and information is improved over previous years. However, it still lacks clarity and robustness. While Hydro One's quantitative evidence is not compelling, the Board finds that Hydro One's qualitative evidence provides assurance that capital costs are escalating significantly. The Board accepts that the high growth period of the 1950s and 1960s likely results in a similar period of a high number of assets coming to the end of their useful life. Though the most recent failure information did show some improvement in failure trends, the Board also acknowledges Hydro One's position that plans for sustaining investment must take into account more than a one-year or short-term improvement when planning capital spending programs. In addition, the Board notes Mr. McQueen's evidence that increasing costs are also a result of escalating global demand for material and equipment. No intervenor refuted this evidence. Therefore, the Board accepts that both the number of replacements and the cost per replacement are escalating.

Intervenors asserted that Hydro One could have avoided the proposed significant increase in expenditures by recognizing the asset aging problem sooner and smoothing the expenditures over the past several years. The Board accepts that it is difficult to smooth a capital budget over several years and that it is both imprudent to invest too soon in capital replacements and imprudent to wait until the system deteriorates to very low levels of reliability before action is taken. Hydro One must balance the immediate investment needs of the system with an eye to proactive action to prevent an unsupportable level of failure and reliability levels.

AMPCO submitted that a large capital investment program should result in lower sustaining capital expenses and suggested that the Board should take this into consideration. The Board agrees that the replacement of old equipment during a capital program should have the effect of lowering sustaining capital costs. We anticipate that there will be a lag in the effect, and expect Hydro One to provide evidence on the 2009 and 2010 sustainment capital benefits of 2007 and 2008 capital expenditures as the newer facilities come into service and replace the aging fleet. However, the Board does not accept AMPCO's rationale for its recommended reduction to OM&A expenses for the test years.

The Board approves the amounts applied for sustaining capital in 2007 and 2008 rates. As noted earlier in this decision in the OM&A chapter, the Board must have improved asset aging data for the next Hydro One cost-of-service proceeding. In approving the Sustaining capital investment plans, the Board expects Hydro One to continue to improve its asset condition assessment work and its work on the influence of asset aging on investment levels. The Board refers the reader to Chapter 3 of this decision for the Board's direction on developing this information.

5.2 DEVELOPMENT

The Development budget is growing from $179.4 million in 2006 to 298.7 million in 2007, an increase of 66% with a further increase of 37% in 2008 to a level of $409.4 million.

The Development Capital category covers funding for projects related to new or upgraded transmission facilities. Those facilities provide inter-area network transfer capability provide adequate capacity to deliver electricity to local areas, connect new generation and load customers to the transmission system, and maintain the performance of Hydro One's transmission system in accordance with Delivery Point Performance Standards. Hydro One showed project detail for all projects with budgets in excess of $3 million.

Hydro One classified the proposed Development projects on the basis of in-service date and the nature of the approval the applicant was seeking from the Board.

Category 1 included 15 projects with in-service dates in 2007 and 2008. The Applicant seeks to include the budgeted expenditures in the rate base the Board for 2007 and 2008.

Category 2 included six projects with in-service dates in 2009 and 2010. These projects do not require Board approval pursuant to section 92 (leave to construct), but will come before the Board again when the Company applies to include the costs associated with them in rate base. As these projects require significant spending in 2007 and 2008, the Applicant seeks assurance from the Board that the projects appear to be necessary, and the costs of the projects appear to be reasonable and prudent. The most significant project in this group is the Claireville/Cherrywood 500 kV circuit unbundling project.

Category 3 included seven projects that will require section 92 approvals. In the course of those proceedings the Company will present evidence establishing need and cost. However, for reasons that will be outlined below, Hydro One requested a determination by the Board of the need for the Leaside to Birch Junction project in this proceeding.

Category 4 consisted of two projects which may be part of the Integrated Power System Plan process, and which will have in-service dates beyond the test years. The evidence regarding these projects will be brought before the Board in a subsequent rate proceeding for inclusion in rate base. The Company did not seek any decisions from the Board with respect to these projects in this proceeding, and the Decision does not comment on those projects.

Board Findings – Development Category 1 Projects

In the Board's view, Hydro One's justification for the bulk of Category 1 projects was extensive and thorough. Support for these projects from sources such as the OPA, the IESO and preliminary documents related to the IPSP is persuasive. The Board also notes the support provided by Toronto Hydro and OPG for some of these investment projects.

There were no Intervenor or Board staff concerns with any of the Category 1 projects. The Board is of the view that these projects are well documented and substantiated by the evidence presented by Hydro One. The Board approves the inclusion into rate base of the budgeted amount of these projects. The total amount projected to be included in rate base in connection with the Category 1 projects is $256 million.

Board Findings – Development Category 2 Projects

Of the Category 2 projects, the Claireville/Cherrywood project was the most discussed. This project, which has an expected capital cost of $107 million, involves unbundling two 500 kV lines that are now connected and operated as a "super" circuit. Currently when one of the two circuits is out of service due to a planned or forced outage, generation connected to the 500 kV system in eastern Ontario must be curtailed. If constructed, the project will result in over 3,000 MW of transfer capability between the Claireville and Cherrywood transmission stations. The project was included in the June 2006 and March 2007 editions of the IESO's Ontario Reliability Outlook ("ORO").[15]

[15] In its final argument, the IESO said that "The inclusion of a project in the ORO … underscores the IESO's assessment that a proposed project meets a reliability need that has been identified or confirmed by the IESO. … To be clear, the inclusion in the ORO is not a directive for a transmitter or other entity to undertake construction, but agreement from the IESO that the proposal meets a specific need to improve reliability of the IESO-controlled grid or the load it serves."

Intervenors were generally in support of the Claireville/Cherrywood project and found the economics and rationale compelling. Toronto Hydro supports the project as it will improve supply reliability to Toronto's distribution system. OPG supports the Claireville/Cherrywood project as it is critical to the integrity of the power system, and benefits the electricity system and the operations and safety of the Darlington Nuclear station once completed. According to OPG, the project will reduce the risk of sudden generation reduction, which results in a revenue loss per event in the range of $0.5 million to $1 million.

Toronto Hydro also supported the Hydro One Development Capital program, making submissions for 16 specific projects cited in the Hydro One evidence, including several Category 2 projects. PWU supported the Hydro One Development capital budget proposals, citing the IPSP, OPA procurement activities and the IESO ORO reports as justification for these investment plans.

Regarding the Category 2 projects, including Claireville/Cherrywood, VECC was concerned with Hydro One's desire for assurance from the Board that "the capital program that the company is proposing is an appropriate approach, subject to coming back later to demonstrate to you that the costs have been reasonable and prudently incurred." [16] VECC submitted that the Board should not grant this assurance and that any such conclusion should be no more than an observation that the projects are reasonable.

The Board agrees with VECC. The costs of these projects will be subject to approval in a future proceeding. However, the Board does make the observation that these projects appear to be needed and, based on the limited evidence available, the Board did not identify any concerns about the proposed costs. The need for at least some portion of the Claireville/Cherrywood project appears to be non-discretionary. As Hydro One will be returning in 2008 for a 2009 test year application, the Board expects to see updates and progress reports on all these projects at that time, for final scrutiny and

[16] Tr. Vol.2, p.121

consideration of approval of the inclusion of these amounts into rate base. For discretionary projects, the Board expects Hydro One to quantify the reliability and other benefits of the projects.

Board Findings – Development Category 3 Projects

In this proceeding, the Board need make only one finding regarding the Category 3 projects. This is the need determination for the Leaside TS to Birch Junction TS project. Approval of all of the elements of the other projects will be covered under Leave to Construct (section 92) applications.

The Settlement Proposal stated:

> The parties agreed that the Applicant has demonstrated the need to relieve loading on the existing 115kV connection lines and Leaside and Birch Junction TSs.
>
> The Applicant has agreed that the issues regarding options, alternatives and costing of the mitigating alternatives will be deferred from this rate application to be dealt with in a separate section 92 application to the Board.

Notwithstanding this settlement, the Board determined that the need for this project should be examined on the record. Hydro One presented witnesses to address this issue in the oral hearing and provided evidence of need supported by the IESO and Toronto Hydro. Other intervenors did not comment on the evidence respecting need but submitted that the scope of the finding that the Board makes should not be broader than that agreed to in the Settlement Proposal.

The Board agrees. The evidence clearly demonstrates the need for the project as it addresses specific reliability issues. The Board finds that the need to relieve loading on the existing lines between Leaside TS and Birch Junction TS has been demonstrated. The Board accepts that the issues on options, alternatives and costing of mitigating alternatives be deferred to a section 92 application, as agreed to by parties in the Settlement Decision.

5.3 ECONOMIC JUSTIFICATION OF THE NIAGARA REINFORCEMENT PROJECT

The Board in its July 8, 2005 Decision on the Niagara Reinforcement Project ("NRP") (RP-2004-0476), granted leave to construct without a determination that Hydro One had proven the economic benefits of the project. As part of that decision, Hydro One was directed to demonstrate the benefits when seeking to recover the costs associated with the project. The Company provided evidence respecting the economic benefits of the project in this proceeding.

Hydro One indicated that the NRP, when operational, will increase import capability from New York by 350 MW. To assess the economic benefit of the project, Hydro One compared, for a 30-year period, the cost of acquiring additional generation capacity through the installation of a 350 MW single cycle combustion turbine unit with the NRP costs. According to Hydro One's evidence the present value of the cost of the 350 MW combustion turbine unit is $309 million and the present value of the cost of the NRP of $103 million. The implied net present value is about $200 million.

Part of the evaluation involved estimating the difference in cost between buying energy in the New York market versus producing energy in Ontario from the combustion turbine. The difference was estimated to be about $70 million in favour of the New York purchase option. The assumptions underlying this estimation were the subject of significant cross examination concerning energy price differentials between the New York and Ontario markets.

Intervenors generally did not comment on the NRP economic justification issue in their final submissions. Only VECC raised concerns regarding Hydro One's analysis. While VECC accepted that the NRP offers benefits that allow new generation in the Niagara Peninsula and increases access to imports, it questioned the 30-year time horizon of the analysis. VECC suggested that the Board direct Hydro One to revise its economic analysis of the project, add congestion costs to the calculation and file the revised analysis prior to requesting any determination from the Board that all of the costs of the NRP (when in-service) be recovered from ratepayers.

Board Findings

While the Board agrees that the further analysis suggested by VECC might have been helpful, the Board finds it was reasonable to compare the transmission reinforcement to a 350 MW single cycle gas combustion turbine. The Board accepts that the need for NRP should be assessed based on the circumstances that existed at the time the project was initially conceived and the information available at that time. For this project, the relevant time period was 2004/2005. When the historical context is taken into account, the economic evaluation provided by the Company is sufficiently persuasive to allow the Board to make this finding. The Board accepts the expenditures associated with the project as prudent, and requires no further analysis from Hydro One to justify the expenditures incurred to date.

However, the Board is concerned that the economic evaluation presented by the Company had shortcomings, which should not be repeated in future applications. In preparing economic justification for similar projects, the Board expects a more complete, precise and rigorous evaluation which includes an analysis of the option of not proceeding with a project, (the “do nothing” scenario) and sharply improved efforts to quantify reliability benefits.

Hydro One is seeking extraordinary relief to recover the costs of this uncompleted project in rate base. The discussion of this aspect of the NRP and the Board’s decision on the matter can be found in Chapter 6 of this Decision.

5.4 OPERATIONS AND SHARED SERVICES

Shared Services capital spending for the test years is substantially higher than spending in 2006 and earlier years. This is mainly due to the Hydro One's Cornerstone information technology project.

Phase One of the Cornerstone project involves the replacement of the PassPort asset and work information system with an integrated Enterprise Asset Management application. The evidence showed that capital spending on this phase alone will be $102 million in 2007, with $57 million allocated to the transmission business.

Although there was significant cross examination on this project, intervenors did not address this issue in their final arguments. According to the Company's evidence, the net present value of the first phase of the project is a $60 million cost over the seven years from 2008 to 2015. Hydro One asserts that the benefits of the project will follow full implementation.

Board Findings

Hydro One was able to demonstrate that the Company's information systems cannot provide the information required to efficiently manage its work and assets. Indeed, the difficulty in getting robust asset aging information in this proceeding was partially attributed to the poor information systems. The Board accepts the Operations and Shared Services capital costs for the 2007 and 2008 rate years, including funding for the Cornerstone project. The Board anticipates greater scrutiny of the cost of Cornerstone in the next transmission rate proceeding when more detailed information will be available.

5.5 CAPITAL CONTRIBUTIONS

Hydro One estimated the total cost of Cambridge Preston TS project cost to be $21.2 million. The Company is not requiring a capital contribution from the customer based on the Company's interpretation of the Transmission System Code (TSC). The appropriate interpretation of the TSC regarding capital contributions is being considered in another Board proceeding, the Connections Procedures case (EB-2006-0189). The decision in that case will clarify the interpretation of the relevant sections of the TSC regarding capital contributions.

VECC submitted that if the EB-2006-0189 decision is not rendered in time to have it reflected in the revenue requirement for 2007 and 2008, then a deferral account should be set up to track the impact of any capital contributions, should that decision reflect an interpretation of the TSC contrary to that taken by the Company in this proceeding. Hydro One argued that a deferral account would not be necessary, but if it is determined that a capital contribution is required, a deferral account could be used to adjust rate base. Hydro One indicated that were a capital contribution required, the customer would have to pay $17 million. The Board estimates the effect on the revenue requirement of such a capital contribution would be less than $2 million in 2007 and 2008.

Board Findings

Since the outcome of the EB-2006-0189 proceeding is not known, the Board accepts VECC's position that a deferral account should be established. Entries in the account will be necessary only if the Board's decision in EB-2006-0189 results in the customer being required to make a capital contribution in respect of the Cambridge Preston TS project.

5.6 EARNINGS/SHARING MECHANISM

While VECC and CCC did not recommend a reduction in the proposed capital budget, they did suggest that Hydro One's capital spending plans were too ambitious and there was a risk that they may not be completed as planned. VECC also questioned Hydro One's prioritization methods. VECC suggested that underspending of the capital budget be returned to ratepayers through an earnings sharing mechanism. CCC supported this recommendation.

Hydro One submitted an earnings sharing mechanism was not necessary and cited evidence that the capital additions expected to come into service during the test years were manageable. The Company also pointed out that earnings sharing proposal would be inconsistent with a cost-of-service filing that is based on future test years.

Board Findings

Hydro One submitted evidence comparing the Company's actual capital spending to budget forecasts for the years 2003 through 2006. The results show variances of up to 20%, both positive and negative. The Board is concerned with the magnitude of the variances but has no basis to believe that the forecast budget for 2007 and 2008 will be under spent. The Board finds that an earnings sharing proposal to guard against variances to budget is unnecessary. As a result of the Board's decision to deny Hydro One's request for a 2009/2010 RRAM, the Board expects Hydro One to file a cost-of-service application for 2009 rates. At that time, the Board expects Hydro One to provide evidence on 2007 and 2008 actual capital spending compared to the Board-approved budget. Future decisions on capital budgets will be informed by Hydro One's performance to plan.

SUMMARY BOARD FINDINGS ON CAPITAL EXPENDITURES

In summary, the Board approves the capital budget for 2007 and 2008 as presented by Hydro One. This includes the budgets for all categories of the capital spending including the Operations and Shared Services categories. The Board reiterates the need for more robust data regarding some of the categories of capital expenditures, as outlined more fully in text above, which the Board expects Hydro One to file in its next transmission rates application.

6. HYDRO ONE'S REQUEST FOR SPECIAL TREATMENT FOR DESIGNATED TRANSMISSION PROJECTS

Hydro One requested special regulatory treatment for four transmission projects: the Bruce Project, a proposed new transmission line to support additional electricity generation from Bruce Power and proposed or possible wind generation projects; the Quebec Intertie, a 1,250 MVA interconnection with Hydro-Québec's transmission system; the installation of static VAR compensators in southwestern Ontario; and the Niagara Reinforcement Project ("NRP"), a new transmission line that is virtually complete. Table 5 shows actual and forecast spending on these projects.[17]

For each of these projects, Hydro One proposed:

- Increasing rate base as expenditures are incurred rather than waiting until the projects are in-service;[18]
- Commencing amortization of the project costs as funds are spent (that is, before they are in-service and are being used) and including the amortization in the revenue requirement; and
- Holding Hydro One financially harmless in respect of the designated projects in the event of abandonment for reasons outside the Company's control.

[17] In its evidence, Hydro One referred to these four projects as "supply mix capital projects". It was not clear to the Board why Hydro One decided to use that description. The Minister of Energy's June 13, 2006 directive to the OPA on the supply mix goals of the Integrated Power System Plan did not mention any particular transmission projects. Two of the projects – the Quebec Intertie and the NRP – were planned and approved before the Minister issued the directive. The other two projects are being initiated before the OPA files its IPSP. In this chapter of the Decision, the Board refers to these projects as the "designated projects", not "supply mix capital projects."

[18] Hydro One also requested that this adjusted rate base would be used to set the revenue requirement under the Company's proposed revenue requirement adjustment mechanism for 2009 and 2010. As noted in Chapter 2 of this Decision, the Board denied Hydro One's request for the RRAM. Therefore, this request is now moot.

The proposed approach differs from the conventional regulatory approach of capitalizing interest costs during construction, and waiting until the project is in-service to transfer the costs to rate base and to commence amortization.

Table 5: Actual and Forecast Expenditures on the Designated Projects

($ millions)	*Historic*		*Bridge*	*Test*		*Total (including future years)*	*Expenditure Period*
	2004	*2005*	*2006*	*2007*	*2008*		
Bruce Project	-	-	-	5	52	613	2007 - 2011
Quebec Intertie	-	-	1	65	48	115	2006 - 2009
Static Var Compensators	-	-	-	-	10	54	2008 - 2009
Niagara Reinforcement	1	35	61	2	0	101	2004 - ?? *
Total	**1**	**35**	**62**	**72**	**110**	**883**	

* Project is almost complete but work has been suspended.

Only three projects were designated for special treatment in Hydro One’s September 2006 application; the NRP was added when the Company amended its application in February 2007. As most intervenors noted, the NRP is fundamentally different from the other three projects in that it is substantially complete but work has been halted because of events outside of Hydro One’s control. In this chapter, the Board deals with the other three projects in section 6.1 and then separately considers the NRP in section 6.2.

6.1 BRUCE PROJECT/QUEBEC INTERTIE/STATIC VAR COMPENSATORS

Hydro One’s primary rationale for the proposed special treatment is that the designated projects require significant expenditures, must be initiated in the short term, have long lead times, are driven by Ontario’s supply mix initiatives, and are exposed to risks over which Hydro One has limited or no control or influence.

Hydro One submitted that its proposed regulatory treatment is consistent with the approach recently adopted by the Federal Energy Regulatory Commission ("FERC") in the United States, will result in a neutral bottom line and will mitigate rate shock and, will result in ratepayers, the primary beneficiaries of the projects, bearing the risks.

FERC Policy and Precedents

To stimulate private capital investment in transmission infrastructure, the United States Congress directed FERC to establish incentive-based rate treatments to promote investment in transmission infrastructure. In 2006, FERC issued Order No. 679, which identifies the types of rate incentives that FERC will consider for federally-regulated transmission entities when justified by the specific facts and circumstances.[19] The identified incentives include higher rates of return on equity for specific transmission investments; the inclusion of 100 percent of construction work in progress ("CWIP") in rate base; and the assurance of recovery of the costs of a project that is abandoned for reasons outside the control of the utility.

In its evidence, Hydro One cited four transmission projects for which FERC approved various incentives. Table 6 summarizes those projects and the incentives granted by FERC. The American Transmission Company decision pre-dated Order No. 679. The other decisions were issued at the same time or after the issuance of Order No. 679[20].

[19] Federal Energy Regulatory Commission, Order No. 679, *Promoting Transmission Investment Through Pricing Reform*, July 20, 2006. In December 2006, after rehearing certain issues, FERC issued Order No. 679-A, which clarified and amended some aspects of the original order but did not change the overall framework for transmission incentives.

[20] After the oral hearing was completed, Staff circulated *Commonwealth Edison Company*, 119 FERC ¶ 61,238 (2007), the most recent decision on incentives for transmission projects, to all parties. The Board did not rely upon it in making its decision.

Table 6: Recent FERC Cases on Incentives for Transmission Projects

Proponent	Project	Cost (US $ millions)	FERC Incentives
American Transmission Company[21]	Various proposed projects over 10 years	Up to $2,800	▪ 100% of CWIP in rate base ▪ Expense pre-certification costs ▪ Increased ROE
American Electric Power[22]	550 miles of 765 kV lines from West Virginia to New Jersey Target completion date – 2014	$3,000	▪ 100% of CWIP in rate base ▪ Option to expense pre-commercial costs ▪ Increased ROE
Allegheny Energy[23]	240 miles of 500 kV lines from Pennsylvania to northern Virginia Target completion date – 2011	$820	▪ 100% of CWIP in rate base ▪ Expense pre-commercial costs ▪ Increased ROE ▪ 100% of prudently-incurred costs on abandonment
Duquesne Light[24]	New high voltage line; increase capacity of underground 345 kV lines with advanced technology; upgrade certain 69 kV facilities to 138 kV. Target completion date – 2009 (some work already complete)	$184	▪ 100% of CWIP in rate base ▪ Expense pre-commercial cost ▪ Increased ROE ▪ 100% of prudently-incurred costs on abandonment

While the FERC incentives listed in Table 6 are intended to encourage investment in transmission projects, Hydro One stated a different rationale. In response to a question from the Board Panel, Hydro One said:

> What we're asking for is not an incentive in the traditional use of that word, as far as to provide some incentive to encourage a certain behaviour … [what] we're asking for is special regulatory treatment for these projects as opposed to an incentive to do something before the fact.[25]

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[21] *American Transmission Company LLC*, 105 FERC ¶ 61,388 (2003), and *order approving settlement*, 107 FERC ¶ 61,117 (2004).

[22] *American Electric Power Service Corporation*, 116 FERC ¶ 61,059 (2006), and *order on rehearing*, 118 FERC ¶ 61,041 (2007).

[23] *Allegheny Energy, Inc*., 116 FERC ¶ 61,058 (2006), and *order on rehearing*, 118 FERC ¶ 61,042 (2007).

[24] *Duquesne Light Company*, 118 FERC ¶ 61,087 (2007), rehearing pending.

[25] Tr., Vol. 7, p. 62

In a concurring statement appended to FERC's decision on the rehearing of the Allegheny Energy application, Commissioner Suedeen Kelly provided a framework for evaluating incentive proposals. She stated:

> I deem it important to identify and assess the following six characteristics of any transmission project in order to make reasoned and consistent decisions on requests for incentives for the project: (1) the public interest benefits of the project; (2) the cost of the project in absolute terms; (3) the cost of the project in proportion to the current transmission rate base of the applicant; (4) the difficulty of completing it due to the number of jurisdictions traversed and whether they are jurisdictions the applicant regularly deals with; (5) the difficulty of relying on normal rate recovery methods due to the length of time it will take to complete; and (6) whether the applicant would otherwise be required to build the project even without an incentive.
>
> The comments submitted in connection with Order Nos. 679 and 679-A, and the experience gained in working on individual incentive cases over the past year lead me to conclude that these particular characteristics are most relevant to deciding whether to award incentives.[26]

A witness for Hydro One said Commissioner Kelly's six criteria "are important characteristics and I believe they're consistent with the criteria that Hydro One has put forward, in terms of assessing the supply mix projects."[27]

Mindful of the fact that there is no government directive in place comparable to that which resulted in FERC Order No. 679, the Board found Commissioner Kelly's framework and criteria of assistance when it considered whether the special regulatory treatment sought by the Applicant for the designated projects was necessary or warranted. While certain of the criteria have reduced significance (for example, the traversing of jurisdictional boundaries poses different problems in the United States than in Ontario[28]) others, such as the costs of designated projects in proportion to rate base

[26] *Allegheny Energy, Inc*., 118 FERC ¶ 61,042 (2007), Kelly concurring statement, p. 1.

[27] Tr., Vol. 6, p. 147

[28]PWU noted, the lion's share of the cost of the Quebec Intertie project will be borne by Hydro-Québec, a fact which may increase the risks associated with that project because it might be dependent on decisions made in Quebec and so beyond the control of Hydro One. Other intervenors, such as CCC, submitted that Hydro One faced no appreciable or substantial jurisdictional risks.

and whether normal rate recovery methods can be relied upon, are of equal significance and importance here.

Many of the intervenors made reference to the criteria in their closing submissions. While none of the intervenors challenged the public interest benefits or the absolute cost of the designated projects, several of the intervenors observed that the aggregate costs of the projects relative to the Applicant's rate base did not present significant risk. Energy Probe noted that, in aggregate, the cost of the projects (including NRP) is less than one-seventh of Hydro One's current rate base, and would be only about 12.8% of Hydro One's forecasted 2008 rate base. PWU made a similar observation. In Energy Probe's view, costs of that magnitude should not create any special risks for the utility, assuming vigilant management. Energy Probe argued that the aggregate costs of the designated projects are comparable to rate base additions in recent years, when no rate changes occurred.

The other criterion which elicited significant comment from the intervenors was whether conventional rate recovery methods were adequate, given the costs of the designated projects and the time period over which the costs would be advanced. It was Hydro One's position that the designated projects are extraordinary in many respects when compared to those normally undertaken by a transmission company, and so merit special rather than conventional regulatory treatment.

VECC submitted the evidence established that the investment community does not perceive an impending risk that would necessitate special treatment. VECC added that regulators in Ontario have considerable experience in dealing with such matters and have traditionally allowed recovery of costs under conventional methods provided the utility has acted responsibly.

CCC submitted that there is no reason to deviate from conventional regulatory approaches and to compensate Hydro One now for risks that have not, and may not, materialize. CCC characterized the proposal by Hydro One to recover a return on expenditures as they are incurred (and to allow for amortization to also be recovered) as a significant departure from the accepted regulatory treatment for capital projects. CCC also pointed out that the bond rating agencies have either maintained positive ratings or improved ratings for Hydro One, without any reference to a need for extraordinary treatment for these projects.

Energy Probe addressed each project separately, and concluded that conventional regulatory treatment was appropriate for all three of the designated projects.

AMPCO submitted that there is no evidence to suggest that, in the absence of special treatment, Hydro One will be left with abandoned or stranded assets from undertaking these projects. AMPCO pointed out that Hydro One may always seek relief from the Board should such an event occur.

Both CCC and VECC were of the view that Hydro One’s proposal was solely directed to risk management. VECC observed that the underlying rationale of the FERC initiatives was to provide an incentive to private U.S. transmission owners to make investments, a rationale not present in this case.

The PWU similarly noted that the request for special treatment of the designated projects is not an incentive in the traditional use of the term, as Hydro One is committed to undertake the projects in any case. However, the PWU also submitted that the request is one of fairness in that Hydro One should be protected from any financial harm for reasons outside its control.

Impact on Ratepayers

Hydro One’s application states that approval of special regulatory treatment for the designated projects would lower and smooth customer rate impacts, and have a positive impact on the Company’s credit ratings and borrowing costs, to the benefit of current customers.

Hydro One also suggested its proposal would result in a neutral financial effect. That conclusion is based on qualitative information obtained in a seminar presented by the National Association of Regulatory Utility Commissioners; Hydro One confirmed that no quantitative analysis had been completed to confirm that the proposed approach would result in a neutral financial effect. In response to an interrogatory, Hydro One advised that it had not estimated the impact of the proposal on its credit rating or borrowing costs; however, in response to another interrogatory, Hydro One stated that the Company may be slightly better off financially under the proposal.

VECC estimated a substantial favourable effect on Hydro One's income by 2010, based on the differential between a pre-tax return on equity and AFUDC. VECC submitted that while Hydro One's intent may not have been to be financially advantaged, the result is that it will derive a substantial financial advantage from the proposed treatment. SEC provided estimated impacts over the long term in noting the proposal is, in essence, an interest free loan to Hydro One from ratepayers that will be paid back over 45 years.

Hydro One also argued that a primary benefit of the proposed special treatment is to avoid rate shock for consumers. VECC, in its argument, notes that Hydro One has done no specific analysis of the rate impact of its proposal. VECC provided its own analysis of total bill impact based on conventional rate making practice. VECC submits that the result (less than 0.3% increase in 2012) does not constitute rate shock.

Energy Probe said that the designated projects are each small, relative to Hydro One's overall rate base, and as the projects have unique in-service dates scattered fairly evenly over future years, the overall rate impact under a conventional ratemaking approach is already smooth.

Board Findings

AMPCO, CCC, Energy Probe, SEC, and VECC argued that the proposed special regulatory treatment for the designated projects should be rejected by the Board. PWU was the only intervenor to support Hydro One's proposal. In summary, the arguments against the proposal were:

- There is no reason why Hydro One should be compensated now for risks that may not materialize.

- The proposal is a significant departure from conventional regulatory treatment for capital projects. The Board should permit departures only under very exceptional circumstances and Hydro One has failed to establish that such exceptional circumstances exist. To allow Hydro One the relief it is seeking would set a precedent that may prompt other Ontario utilities to seek similar relief. Before setting such a precedent, the Board must be satisfied that conventional regulatory treatment is inadequate to meet needs such as those associated with the designated projects.

- If construction is delayed or if there are abandonment issues, Hydro One would be free to come to the Board for relief.

- Hydro One has not established that it is now subject to an increased risk with respect to the recovery of the costs associated with these projects.

- Hydro One has not established the need for "incentives" to undertake or complete those projects.

- FERC precedents arise out of a different regulatory regime and are not applicable in the Ontario context.

- The benefits to ratepayers as articulated by Hydro One have been overstated.

The Board shares these concerns and finds that a departure from conventional regulatory treatment has not been justified.

There is no evidence in this case that any regulator other than FERC has approved a package of special regulatory treatments like those advocated by Hydro One. FERC regulatory initiatives can be important guidance in some cases and the Board will continue to monitor FERC's actions to incent new transmission. However, the Board is not convinced that FERC's approach to incentives for transmission investments justifies the special treatment that Hydro One has requested. The cost of the designated projects, while large in absolute terms, is not particularly significant in relation to Hydro One's rate base, and there is no evidence that Hydro One will have difficulty financing the projects under conventional regulatory treatment.

The Board is not persuaded that ratepayers would benefit from the proposed special regulatory treatment. Specifically, the Board does not accept Hydro One's argument that the treatment would result in revenue neutrality and rate smoothing. The evidence from Hydro One on this point was in conflict and lacked substance.

The Board acknowledges Hydro One's concerns about the magnitude of its capital expansion program. At the same time, based on the evidence from the credit rating agencies, the Board is not convinced that Hydro One will be unable to finance the capital program under the conventional approach.

The Board is of the view that conventional regulatory treatment for the three designated projects provides the appropriate balance between the interests of ratepayers and utilities. The Board agrees with the consensus position of the intervenors that the mitigation of losses that have not, and might not, occur is unnecessary and not appropriate. There is nothing in the record that would justify the burdening of ratepayers with such losses. In addition, Hydro One is reminded that it can come forward with applications for relief, if a special circumstance arises which puts it clearly at risk. The Board has promptly responded to such requests from other applicants in the past. There is no reason to expect that the Board would not deal fairly and promptly with Hydro One on these projects should significant issues arise in the future.

Hydro One's request for special regulatory treatment for these designated projects is denied. In reaching this decision, the Board is not ruling out providing incentives for future projects where there is a compelling case.

6.2 NIAGARA REINFORCEMENT PROJECT

Hydro One was granted approval by the Board in July 2005 to construct the NRP and construction began shortly thereafter. As the result of a land claim by aboriginal peoples and the occupation of a portion of the lands necessary for the completion of the last two kilometers of the project, the project has been frustrated, pending a multi-lateral resolution of the underlying land claim issues.

CCC, SEC and VECC supported some form of relief regarding the NRP, while AMPCO and Energy Probe were of the view that the project should be accorded conventional ratemaking treatment.

SEC submitted that Hydro One should be allowed to expense, rather than capitalize, the AFUDC associated with the project. CCC suggested that Hydro One should be allowed to expense AFUDC for NRP for 2007 and 2008 only. VECC submitted that the Board could consider allowing AFUDC associated with the NRP to be expensed as opposed to capitalized – effective January 1, 2007. If Hydro One required additional relief prior to the project being completed and in-service, then a specific application should be brought before the Board seeking the same.

The common rationale was that, as a result of factors beyond its control, Hydro One has been prevented from placing the asset in service. All but a very short span of the project has been completed, and the overwhelming majority of the funds needed to complete and make serviceable the reinforcement have been expended. The respective positions of these intervenors reflect their assessment that this is an exceptional circumstance requiring a special regulatory response.

PWU also supported relief on the NRP and advised that the Board should focus on the substantive issues underlying the request for special treatment rather than the question of whether or not the NRP fits into the category of the other three designated projects.

Energy Probe took the position that the appropriate course is to disallow recovery of any NRP costs from ratepayers until the project is in service. Once in service, ratepayers should have to pay all costs, except those incurred from the time the Province bought the land in Caledonia until the project is placed in service.

AMPCO was of the view that as Hydro One had asked that the NRP be considered a supply mix project, it should receive the same treatment as the other designated projects.

Board Findings

The Board's role is to make decisions that are in the public interest and to determine an appropriate balance between the interests of the regulated utility and consumers. The Board agrees that special regulatory treatment is appropriate for the NRP because a recognizable risk has materialized out of the land claim dispute in Caledonia, the resolution of which is beyond the control of Hydro One.

In determining the special relief, it is important to take into consideration all aspects of this project.

Hydro One brought an application to the Board in 2004, requesting approval to proceed with this project. Hydro One's decision to initiate the NRP was not the result of OPA planning. In that 2004 application, Hydro One did not provide what the Board considered to be a sound economic rationale for the NRP. As such, the Board decided that Hydro One would be required to provide an acceptable economic justification in the future before the project costs could be recovered from ratepayers.

Hydro One has now spent $97 million on this project and the Board has received the required updated economic rationale in this application. It is not known if the project will eventually be completed, if it will come into service with a different route and additional costs, or if it must be abandoned and written off. The Board is of the view that it would not be in the public interest to shift the entire financial burden of an asset that is not in service to consumers as requested by Hydro One.

However, Hydro One faces carrying costs for these expenditures and the Board agrees with VECC and CCC that a compromise is appropriate. As CCC, VECC and SEC suggested, the Board has decided to allow Hydro One to expense – rather than capitalize – the AFUDC, or carrying costs, associated with the project based on the actual expenditures made to date. While CCC and SEC suggested it should be limited to the test years, the Board agrees with VECC in that it should be effective January 1, 2007, with no explicit time limit as it remains uncertain when the Caledonia dispute will be resolved. If Hydro One requires additional relief prior to the project being completed and in-service, it is free to bring an application seeking such further relief.

7. HYDRO ONE TRANSMISSION ROE AND CAPITAL STRUCTURE

Return on Equity (ROE)

Hydro One Transmission's revenue requirement for the year 2000, the last time the Board conducted a cost-of-service review of the transmission business, was based on a return on common equity ("ROE") of 9.88%. The Company is requesting an increase to 10% in 2007 and 10.25% in 2008.

Hydro One provided evidence in support of its request through Ms. Kathleen McShane of Foster Associates, who initially argued that an ROE of 10.5% in both 2007 and 2008 was appropriate for Hydro One Transmission. In updates of February 23, 2007 and March 1, 2007, Ms. McShane revised her recommendation on the basis that prevailing market conditions warranted lower ROEs of 10.0% in 2007 and 10.25% in 2008.

Ms. McShane's study made use of the equity risk premium, discounted cash flow and comparable earnings tests. Ms. McShane took the position that her recommendation was demonstrably reasonable in light of returns allowed for Hydro One Transmission's U.S. peers (range of 10.5%-12.5%), with whom she submits Hydro One would have to compete for capital to finance close to $2 billion in transmission-related capital expenditures in the 2006-2008 timeframe, and potentially similar levels for the several subsequent years.

CCC and VECC provided evidence through Dr. Laurence Booth of the University of Toronto, who took the position that a fair ROE for Hydro One Transmission would be approximately 7.50%, including a 50 basis point cushion. Dr. Booth submitted that most of Hydro One Transmission's risk comes from its rate design and the amount of debt financing, not its underlying business risk. Dr. Booth saw underlying business risk to be minimal for Hydro One and most regulated utilities in Canada.

The *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* of December 20, 2006 (the "Cost of Capital Report") incorporates an ROE methodology that, when applied to Hydro One Transmission, produces ROEs considerably lower than the levels proposed by Hydro One and somewhat higher than the level proposed by Dr. Booth. Based on an answer to an undertaking provided by Hydro One, application of the Board's distribution formula to Hydro One Transmission would produce an ROE of 8.53% in 2007 and 8.64% in 2008.

Capital Structure

Hydro One Transmission has a current deemed capital structure of 60% debt, 4% preference equity, and 36% common equity. It is requesting Board approval for a more favourable deemed capital structure of 56% debt, 4% preference equity and 40% common equity.

Hydro One provided evidence in support of its proposed capital structure, again by Ms. McShane, who argued that Hydro One's proposed capital structure was justified in light of its need to maintain an 'A' bond rating. Ms. McShane stated that this bond rating was critical in light of Hydro One's need to access debt markets to finance extraordinary capital expenditures, the more limited market for BBB debt, and the lesser ability of BBB-rated companies to access the long-term (30-year) debt market.

CCC and VECC provided evidence by Dr. Booth on this matter, who recommended that the Board should reduce Hydro One Transmission's allowed common equity ratio to 34%, with a 66% debt ratio. Dr. Booth noted that his recommended common equity ratio was 1% higher than that imposed on the Alberta transmission companies regulated by the Alberta EUB. During his examination-in-chief, Dr. Booth stated that he viewed transmission assets as the lowest risk regulatory assets in Canada, mainly because transmission is a natural monopoly and an essential component in the distribution of electricity. Dr. Booth also noted that Hydro One had the highest bond rating of any regulated utility in Canada. The Board notes that while Hydro One owns over 97% of the transmission system in Ontario, it is not, strictly speaking, a “monopoly”.

The Cost of Capital Report incorporates a capital structure policy for distributors of 60% debt and 40% equity. This is in line with Hydro One Transmission’s presently approved deemed capital structure.

Transmission versus Distribution Risk Differentials

In the course of this proceeding, Board staff retained Professors Fred Lazar and Eli Prisman of York University to undertake a study of whether or not there is a determinable risk differential between Hydro One’s distribution and transmission businesses that would justify differences in the allowed capital structures and cost of capital for the respective businesses.

Professors Lazar and Prisman concluded that “at this time, the results are too mixed, and most often statistically insignificant to reach any conclusion other than to award the same ROEs for both the Transmission and Distribution segments of Hydro One.”

Ms. McShane took a similar view noting that the difference in the level of risk between Hydro One Transmission and Distribution is not material enough to distinguish between the two in terms of either recommended capital structure or return on equity.

Dr. Booth expressed the view that Hydro One Transmission is of lower risk than Hydro One Distribution. During his cross-examination, Dr. Booth stated that he would be amenable to the use of the Board’s distribution rate of return mechanism to set Hydro One Transmission’s ROE, but only on the basis that the Board adjust for Hydro One Transmission’s lower risk through a lower common equity ratio.

Cost of Debt and Preference Shares

Hydro One provided its derivation of the forecast yields for each of the debt issues anticipated for 2007 and 2008, which were based on forecast Government of Canada yields for 5, 10 and 30 year debt with a Hydro One spread applied to them.

Although Ms. McShane updated her evidence on February 23, 2007 and March 1, 2007, and concluded that prevailing market conditions justified a lowering of her ROE recommendation, Hydro One did not update its debt and preference share costs to reflect the changes in market conditions that had occurred since its evidence had been filed in September 2006.

During cross examination, Hydro One acknowledged that it had not updated these costs and had issued new 30-year debt in March of this year. The Company acknowledged that there would be a difference between the cost of that new debt compared to the cost of debt assumed in the evidence. Specifically, the coupon rate of the 30-year debt assumed in the evidence was 5.53%, but the new debt had been issued at a coupon rate of 4.89%.

Hydro One explained that the reason it had not updated these costs while updating its ROE estimate was that the impact of any such update would be far more significant on the ROE than it would be on the cost of debt, as the cost of debt is based on a full portfolio of outstanding bond issues that incorporate placements going back a number of years. Also, Hydro One stated that it viewed the cost of debt as but one of a bundle of assumptions embedded in its Application, and it did not propose to revisit the full suite of its planning assumptions as the revision of some may have been more favourable to one stakeholder, while the revision of others may have been more favourable to another.

Treatment of Designated Projects – Impact on Capital Structure/ROE

Ms. McShane's initial evidence on ROE was submitted with the presumption that three designated capital projects would receive the special treatment applied for. The NRP was not initially included among these projects or as part of her assumptions.

Hydro One subsequently updated its evidence to include the NRP in its request for special treatment of the designated projects; however Ms. McShane's evidence update did not make any reference to this apparent reduction in Hydro One's risk profile.

During cross-examination Ms. McShane was asked about the impact on her recommendations if Hydro One's request for the special designated project treatment was denied. She stated that the ROE calculation would have to be adjusted upward by 25 to 35 basis points, or alternatively that a two-and-a-half to three percentage points increment in the equity ratio would be necessary. Ms McShane noted that her preference was for an adjustment to the equity ratio.

The Board's consideration of the proposed treatment of the designated projects, including the NRP, is dealt with in Chapter 6 in this Decision.

Board Findings

Hydro One asserted that its proposed increase in ROE is necessary to enable it to access capital markets effectively, and to borrow the very large sums needed to fund the expansion and reinforcement of the transmission system at interest rates that are as low as possible.

Access to these markets, and the costs of borrowing, are often seen to be dependent on the opinions expressed by various bond rating organizations. One of the key factors used by these agencies to assess the credit-worthiness of a borrower is the adequacy of its ROE in light of the business risk associated with the borrower. If the ROE is seen to be low given an entity's business risk, the cost of borrowing will rise to account for it. If the disparity is too great between the ROE and the inherent business risk, funds may not be available at all.

In this way, the Company's proposal for an increased return on equity, and an increase in the equity portion of its deemed capital structure, is bound up in many of the other proposals forming part of this rates proceeding.

It is also true that the comparative risk faced by the transmission business of the Company was an overarching theme of this Application. The Company sought to limit or eliminate the regulatory risks it is facing. Hydro One was concerned that the Company would not be granted recovery for expenditures prudently incurred. This is seen in the proposals for the designated projects, and in the assurances requested for portions of the capital projects budget, and in the Company's RRAM proposal.

To consider the Company's proposal, it is necessary to consider the riskiness of its operating environment, the perception of that environment by market analysts, and the appropriateness of the Board's methodology in establishing the appropriate ROE and capital structure.

As the operator of the vast majority of the transmission system in the province, the Company is uniquely capable, and uniquely positioned, to make a wide range of informed decisions respecting system growth and reinforcement. The ratepayer is entitled to expect that the Company makes careful, engineering-based plans, founded on its best judgement as to what the system needs.

Where line connection enhancements are made, the TSC provides a formulaic approach directed to assessing the prudence of a project, and the extent to which those directly benefited by the project are required to contribute capital. This serves to limit the exposure of the transmitter to risk. Although the same formulaic methods do not exist to assess prudence and cost recovery for large capital projects, Hydro One has ample opportunity to address these issues in Leave to Construct applications and rate cases.

A utility which has followed reasonable engineering and financial practice, and has applied the TSC appropriately, is unlikely to be denied recovery of prudently incurred costs. Similarly a utility which is confronted with unusual circumstances is unlikely to be denied relief when events out of the utility's control occur. Indeed, the response of the Board and the intervenors to the Company's dilemma respecting the NRP is evidence of a regulatory approach in the province that is flexible and responsive. This positive regulatory environment is noted in one of the bond rating agency reports.

The Board recognizes that some of the projects the Company becomes involved in are very large, both in terms of their related costs, and their potential impact on the effectiveness of the overall provision of electricity to the province's residents and businesses. It is understandable that the Company has concerns respecting its ability to recover the very large sums that it commits to such projects; however, the Board cannot discern any significant risk for the Company that it will be unable to recover prudently incurred costs.

Under the concept of just and reasonable rates, the Company has a reasonable and enforceable expectation that its prudently incurred costs will be recovered in a timely fashion. This includes an expectation that in considering the prudence of expenditures, the Board will assess the Company's judgement in light of the circumstances prevailing at the time the expenditure is made, and without the distraction of hindsight. The Company's prudence should be adjudicated on the basis of what it knew or ought to have known at the time the expenditure was made, not on the basis of subsequent events or conditions, which may have the effect of making the expenditure appear to be unwise.

There is always a risk that if the Company fails to use good judgement in formulating its plans, or otherwise incurs costs imprudently, it will not be authorized to recover such costs. That is a risk that the Company must bear on its own. No responsible regulator can protect a utility from imprudence, poor judgement or laxity. Nor, to be fair, does Hydro One appear to be asking for protection from these.

The evidence respecting the observations of the bond rating services suggests that they are much more confident than the Applicant in the regulatory regime governing the company's operations. This was particularly evident in the examples cited during the cross-examination of Ms. McShane by counsel for CCC.

One analytical tool useful in determining the appropriate ROE and deemed capital structure lies in assessing the extent to which the transmission business can be considered to be more or less risky than the distribution business. The Board's recent consideration of cost of capital in the Cost of Capital Report is of assistance in determining an appropriate ROE and capital structure for the applicant's transmission business.

The Board has examined the fundamentals of its ROE methodology on a number of occasions in the recent past. The Cost of Capital Report is only the most recent example. In each case, the Board's use of its current methodology has been confirmed.

The Cost of Capital Report was generated to inform the Board with respect to the appropriate ROE and capital structure for the local distribution companies, including Hydro One in its operation of a substantial distribution network. It follows that a consideration of the relative risks as between the transmission business and the distribution business should inform a consideration of the appropriate ROE and deemed capital structure for the transmission business.

Importantly, most of the experts providing evidence in this case were unable to conclude that there was any material difference in the level of risk between the distribution and the transmission undertakings. Dr. Booth alone suggested that transmission was less risky, and therefore should be subject to a lower overall ROE.

With respect, Dr. Booth's view seemed to be analytical, and not data based. He referred to the approach taken by the Alberta Board in the case of Altalink, a comparator that was not demonstrated to be apt.

It is the Board's view that there really is no convincing quantitative evidence before us which suggests that transmission is more or less risky than distribution. It is true that distribution has greater and more immediate exposure to the possibility of bad debts. On the other hand, in absolute terms, the transmission system involves very large capital projects of significant complexity, which can be subject to delay in completion, and consequential delay in expected revenues. On balance, the Board concludes that the evidence before us does not provide a basis upon which we can make a finding that there is any meaningful difference in risk as between distribution and transmission.

The Company is in a unique position compared to other utilities in the province. It alone among all of the utilities in Ontario operates a major transmission business and an equally large distribution business. If the Company believes that there is a significant risk differential between its two business segments, it should have been able to present much more convincing evidence respecting the relative risks. The fact that it did not is telling.

It follows that the ROE for the transmission arm of the company should not enjoy a different ROE than that governing its distribution business.

Accordingly, the Board finds that the ROE formula for electricity distributors, as documented in the December 20, 2006 Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation Mechanism, shall be applied to Hydro One Transmission. The Board has determined that Hydro One's ROE shall be derived based on an application of the Board's formula as of January 1, 2007, using December 2006 *Consensus Forecasts* and Bank of Canada data. This should result in an ROE of 8.35% for both 2007 and 2008.

The Board notes that all of the consumer intervenor groups were receptive to the use of the Board's distribution formula for setting ROE, although most also argued that Dr. Booth's lower recommended common equity ratio should be applied in establishing Hydro One Transmission's capital structure. However, as has been discussed, the Board has not been presented with any convincing quantitative evidence in this proceeding which suggests that transmission is more or less risky than distribution. Accordingly, the Board will also apply the distribution capital structure to Hydro One Transmission.

The Board has further determined that Hydro One's debt costs will not be updated. The Board notes the comments of some intervenors that the Board should require Hydro One to update its forecast debt costs, as is done for the regulated natural gas utilities. The Board notes that in recent gas proceedings where this has been done, it has usually arisen out of rates agreed to by the respective parties and included in the Settlement Agreements. In the absence of such a settlement on this issue in this proceeding, the relative magnitude of the amounts involved, and the uncertainties surrounding changes in interest rates and Hydro One's financing plans, the Board is not convinced that the cost of debt should be updated and will use the rates contained in Hydro One's application for the purpose of rate-setting.

8. DEFERRAL ACCOUNTS

8.1 ONTARIO ENERGY BOARD COST ACCOUNT

Hydro One has used this deferral account to capture the excess of OEB cost assessments during the past several years over the amount included in Hydro One's last approved revenue requirement. The account also includes capitalized interest. Hydro One requested Board approval of the balance of the account and its disposition over four years.

The account was established by Hydro One in 2004. The amount charged to the account in that year, $4.6 million, apparently included amounts dating from 2000.[29] The account balance was $4.8 million at the end of 2005, $7.1 million at the end of 2006, and $7.9 million at April 30, 2007.

The balance of the account and its disposition were settled issues in the Settlement Proposal but the settlement was not accepted by the Board.[30] In its Settlement Decision, the Board instructed Hydro One to provide additional evidence to establish why the Company should recover such costs, given that it did not have a Board-approved deferral account at the time the costs were being incurred.

Hydro One provided a copy of a December 2004 letter to Board staff indicating the Company's intention to implement deferral accounts and practices for tracking OEB costs, similar to those approved by the Board for use by electricity distributors. Hydro One also stated that since 2004 it has consistently included the account in its quarterly reporting, pursuant to the Board's Recordkeeping and Reporting Requirements.

[29] Tr. Vol. 7, p. 178, lines 11 to 15.

[30] EB-2006-0501, Settlement Proposal Decision, April 18, 2007, p. 6.

There is no evidence that the Board's staff acknowledged Hydro One's December 2004 letter or that the Board otherwise approved the deferral account.

Hydro One's position is that OEB costs affect its transmission and distribution businesses in an equivalent manner and it is appropriate for both businesses to maintain a deferral account for these costs. With respect to the lack of approval, Hydro One stated that "the failure to establish an official deferral account was an oversight arising out of a misunderstanding between the OEB Staff and the Applicant. Under those circumstances, Hydro One now asks that an official deferral account be established." [31]

Board Findings

The Board cannot accept that the balance in this account should be recovered from ratepayers. Although, as Hydro One suggests, there might have been a misunderstanding, the fact remains that the account has not been approved by the Board.

The Board might have considered approving recovery of the account had the balance resulted from an extraordinary variation in expenses and if the balance were large enough that non-recovery might be a financial burden on the company. In the Board's view, that is not the case here. At least six years have passed since the Board last examined Hydro One's transmission revenue requirement. Over that period, the revenues and expenses of the transmission business have varied, sometimes significantly, from the amounts approved in the last rates case. In a business with annual revenues in excess of $1.2 billion, it does not seem particularly noteworthy that the cumulative variance in a single expense line over that time is $7.9 million (including capitalized interest). The swing in transmission revenues in any year due to weather and other factors has been many times larger than that.

[31] Hydro One Reply Submission, June 13, 2007, p. 57.

As noted in the following section, an earnings sharing mechanism was in place in 2006. Although the Board disallows recovery of the OEB cost deferral account balance, it will permit Hydro One to deduct the growth in the account in 2006 ($2.3 million) from 2006 earnings in calculating excess earnings.

8.2 2006 EARNINGS SHARING MECHANISM

Calculation of Excess Earnings

The earnings sharing mechanism (ESM) was established by the Board in its February 21, 2006 decision on EB-2005-0501. In that decision, the Board determined that excess earnings of Hydro One’s transmission business from January 1, 2006 until new transmission rates are implemented should be shared equally by ratepayers and the Company. Earnings for 2006 were to be determined from actual results as shown in Hydro One’s 2006 audited transmission business financial statements. In its Partial Decision and Order dated March 30, 2007, the Board approved a 2007 Revenue Difference Deferral Account, which had the effect of terminating the ESM as at December 31, 2006.

In its pre-filed evidence, as updated April 20, 2007, Hydro One calculated total excess after-tax earnings for 2006 of $37.5 million, 50% ($18.7 million) of which would be for the account of ratepayers. In calculating that amount, Hydro One decided to exclude two 2006 income statement credits aggregating $30.2 million, after tax:

- A tax benefit of $16.4 million that was recognized in the first quarter of 2006. According to the 2006 audited financial statements of Hydro One’s transmission business, the benefit related to a “recovery of PILs from prior years following a successful appeal allowing a deduction for certain overhead costs that had been previously capitalized.”

- A $21.6 million recovery in 2006, recorded as a reduction of OM&A expense, of property taxes for the years 1999 to 2005 inclusive. The after-tax impact of this item was $13.8 million.

In its final argument, Hydro One indicated it would increase its calculation of excess earnings as a result of reallocating expenses from its transmission business to its distribution business. This adjustment was made after discussion in the hearing about how to apply the requirements of the Board's February 21, 2006 decision that established the ESM.[32] In its reply argument, Hydro One noted that this reallocation would increase excess pre-tax earnings by $9.5 million ($6 million after tax).

Hydro One submitted that it is appropriate to exclude the two items from income because they resulted from the resolution in 2006 of issues that arose in prior years. In support of its position, Hydro One cited a 2004 Board decision on an Enbridge Gas Distribution earnings sharing mechanism,[33] in which the Board directed Enbridge to exclude from its calculation of excess earnings the write-off in 2004 of a non-recoverable receivable (the balance in a deferral account established in an earlier period). The decision stated: "Earnings determinations should be unfettered by differing accounting treatments and related reporting inclusions and exclusions."

Intervenors disagreed with the exclusion of the two items from the calculation of 2006 excess earnings. They submitted that it is clear from the Board's decision on EB-2005-0501 that the excess earnings should be calculated from the unadjusted 2006 audited financial statements. Hydro One submitted that the intervenors who oppose Hydro One's adjustments are reversing the position they took when they supported the exclusion of expenses from Enbridge's earnings sharing mechanism in 2004. SEC argued, however, that the Board's intent in the 2004 Enbridge Gas Distribution decision

[32] In its decision on EB-2006-0501, the Board ordered Hydro One "to report revenue changes for the 2006 rate year resulting from the Board's decision on cost allocation in RP-2005-0020/EB-2005-0378. The [cost allocation] report will be reviewed with the objective of crediting the resultant cost allocation adjustment to transmission customers in the 2007 rate application." (p. 6)

[33] RP-2003-0203/EB-2004-0468, Decision With Reasons, November 24, 2004.

was simply "to avoid the absurd result whereby an amount previously adjudged to be non-recoverable from ratepayers would become partially recoverable as a result of the earnings sharing mechanism".[34]

Proposal to Treat Excess Earnings as a Capital Contribution

Hydro One proposed that the pre-tax amount of the ratepayers' share of the 2006 excess earnings be treated as a capital contribution (that is, the amount would be treated as a reduction of rate base) to be applied against two capital projects that under development.[35] Ratepayers would receive the benefit of the excess earnings through reduced charges in the future for both depreciation and return on capital.

The capital contribution treatment was proposed by Hydro One when the Board first established the ESM in February 2006. The Board did not accept the treatment at that time but indicated that Hydro One could bring the matter forward at the time of disposition of the account balance.

Hydro One cited some U.S. cases as precedents for the capital contribution treatment. In response to concerns that its capital contribution proposal creates intergenerational equity issues (by stretching out the return of the excess earnings to ratepayers over several decades), Hydro One suggested it could credit the excess earnings against capital projects with much shorter useful lives, such as the Cornerstone IT project.

Intervenors were opposed to the capital contribution approach. They objected to ratepayers, who overpaid for transmission service in 2006, receiving the benefits over a protracted period starting in 2009 when the two capital projects are to be in service. AMPCO also argued that capital contribution mechanisms are designed to protect ratepayers who will not benefit from projects requested by specific customers. In

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[34] SEC Final Argument, p. 44.

[35] The projects are the Southern Georgian Bay Reinforcement and the Hurontario Switching Station. The aggregate estimated cost of the projects is $135 million. Both developments are expected to be in service in 2009.

AMPCO's view, such mechanisms are inappropriate for returning overearnings to ratepayers.

The intervenors argued that excess earnings should be returned to ratepayers over a much shorter period, either over two years (2007 and 2008) or over four years (the period over which other Hydro One deferral accounts are cleared). CCC, SEC, and VECC supported netting the balance against the RDDA balance (see section 8.3 below) and including the net amount in the revenue requirement over either two or four years.

Board Findings

The Board does not agree with the proposal to exclude the two income items from the calculation of 2006 excess earnings. The Board finds that the EB-2005-0501 decision which established the ESM is clear that the 2006 audited income statement (called the Statement of Operations by Hydro One) is the basis for the calculation. There is nothing in that decision that suggests Hydro One was to have discretion to exclude any income or expense. The section on page 10 of that decision entitled, "By what mechanics should excess earnings be established?" sets out a mechanical approach to the calculation that does not provide for adjustments for "prior period" or "non-recurring" items. In fact, that section states: "The following items will be sourced from the audited financial statements (Transmission): Net Income (actual, not normalized for weather) – from Statement of Operations."

Although the two items in question result from resolution of issues that arose in prior periods, neither item apparently qualified as a prior period adjustment under generally accepted accounting principles; had they so qualified, they would have been omitted from the 2006 audited income statement and included in restated prior period financial statements.

The Board does not agree with Hydro One that the 2004 Enbridge Gas Distribution decision is a relevant precedent. The decision that established the Hydro One ESM is so clear on how the calculation is to be done that there is no need to seek guidance from any other source. In addition, as noted by SEC, the 2004 Enbridge decision concerned the write-off of a regulatory balance that apparently had been determined to be uncollectible from ratepayers, so it would make little sense to require ratepayers to absorb some of that amount thorough an ESM.

The Board will require Hydro One to recalculate the amount of excess 2006 earnings without exclusion of the two income items. As noted in section 8.1 on the OEB cost account, the Board will also permit Hydro One to deduct the growth in that account in 2006 in determining excess earnings.

The Board does not accept the capital contribution approach proposed by Hydro One. In the Board's view, it is important that overearnings be returned to customers as soon as possible; the capital contribution approach results in an inappropriately long "refund" period. That is true even if the excess earnings were to be credited against a capital project with a shorter life than a transmission station. The Board finds that the balance in the ESM account should reduce Hydro One's revenue requirement at the first available opportunity, which is the revenue requirement for the years 2007 and 2008.

8.3 2007 REVENUE DIFFERENCE DEFERRAL ACCOUNT

This account was approved by the Board in a March 30, 2007 Partial Decision and Order. It is intended to capture the difference (positive or negative) between (a) revenue determined using the rates resulting from this proceeding, and (b) revenue determined using currently approved transmission rates. The revenue difference is to be calculated for the period from the effective date of Hydro One's new revenue requirement to the date on which new uniform transmission rates are implemented. The Board did not make a decision on either the effective date or the implementation date in its March 30, 2007 Partial Decision and Order. The Board also did not decide whether the revenue amounts should be based on actual or forecast load.

During the hearing, Hydro One witnesses presented the Company's proposal on the calculation of the balance in the Revenue Difference Deferral Account ("RDDA") and the manner in which new rates should be implemented (Exhibit L7.1). Hydro One proposed that:

- The new revenue requirement resulting from this proceeding should be effective January 1, 2007;
- New uniform transmission rates should be implemented November 1, 2007; and
- The RDDA balance for the 10 months to October 31, 2007 should be calculated based on forecast load, not actual load.

Hydro One set out two options for making the rate change. The first option, and Hydro One's preference, is to implement a single rate change on November 1, 2007 to collect the approved 2007-2008 revenue requirement for the next 14 months and the balance in the RDDA. The second option would be to have two rate changes – one on November 1, 2007 and a second on January 1, 2008.

Three intervenors (CCC, SEC, and VECC) argued that the effective date of the new revenue requirement should depend on whether it is higher or lower than the revenue Hydro One would earn at current rates. If the new approved revenue requirement is lower, all three supported an effective date of January 1, 2007. If the new requirement is higher, all three advocated a later effective date. CCC and VECC supported May 1, 2007, the date Hydro One requested in its initial application. SEC submitted that a higher revenue requirement should only become effective when new uniform transmission rates are implemented. The intervenors acknowledged the assymetrical nature of their recommendations but submitted that the result would be fair given that Hydro One filed its application less than four months before the beginning of 2007. SEC explained its position this way:

> SEC understands that at first blush that position may seem contradictory or even unfair to the Company. However, it is the applicant that controls the timing of rate applications. Accordingly, the Applicant should be at risk of not recovering its revenue deficiency in the event it does not file in time to have its rates in place at the beginning of the test year. It is not acceptable, however, for the Applicant to risk the ratepayers' money by filing in such a way as to ensure that a portion of a rate reduction is not paid to ratepayers as a result of the timing of the application.[36]

With respect to the calculation of the balance in the RDDA, AMPCO supported using actual load while CCC supported using forecast load. Both intervenors supported the first rate implementation option, a single rate change on November 1, 2007. VECC argued that Hydro One should be directed to come forward with a detailed implementation plan once the 2007-2008 revenue requirement is approved.

In reply, Hydro One stated that a January 1, 2007 effective date is simple to implement. It submitted that it was not possible for the Company to file an application any earlier than September 2006. It also said that the intervenors' request for different effective dates depending on the amount of the new revenue requirement was not fair and balanced.

Board Findings

This is the first application by Hydro One Transmission in many years and there is no well established practice for determining the effective date of a new revenue requirement for this business.

The Board acknowledges the intervenor comments that there was no prospect of new transmission rates being implemented on January 1, 2007 given that the application was filed in mid-September 2006. The Board notes that the pooled uniform rates used for electricity transmission in Ontario necessarily will result in a longer period between the application date and the implementation of new rates than is the case in gas and

[36] SEC Final Argument, p. 39.

electricity distribution. For this reason, the Board is not as concerned as some of the intervenors about the relatively short period between the timing of Hydro One's application and its request for a January 1, 2007 effective date.

The Board has determined that Hydro One's new revenue requirement should be effective January 1, 2007. This approach aligns the start date of the new revenue requirement with the beginning of the 2007 test year for which Hydro One filed considerable evidence and analysis. A later date would effectively result in three different revenue calculations for the 2006-2007 period (2006 – revenue based on current rates, adjusted for the ESM; 2007 up to effective date – revenue based on current rates; 2007 after effective date – revenue base on new rates).

The Board is also not supportive of selecting an effective date that is always to the disadvantage of the Applicant, which is what several intervenors advocated (that is, an early date if the revenue requirement falls but a later date if the revenue requirement is increasing). The Board agrees with Hydro One that this would not be fair and balanced.

The Board accepts the use of forecast load to calculate the RDDA balance since that is consistent with the way new rates will determined. The Board also agrees with the first option to rate implementation (a single rate change targeted for November 1), which is a relatively simple approach.

9. LOAD FORECAST

Rates for each of Hydro One's three transmission charge pools – network, line connection, and transformation – are based on a customer's coincident or non-coincident peak load. Thus, a peak load forecast is required to translate the Board-approved revenue requirement for 2007 and 2008 into rates. Customer rates per kW of load are directly affected by the forecast used to derive the rates.

Table 7 shows Hydro One's forecast of average 12-month peak load for the test years for Ontario as a whole and for Hydro One's individual charge pools. Hydro One's estimates of the impact of embedded generation and conservation and demand management (CDM) are also shown.

Table 7: Hydro One Load Forecast

12-month average peak load in MW	ONTARIO DEMAND	HYDRO ONE CHARGE POOL		
		Network	Connection	Transformation
2007				
Forecast before embedded generation and CDM	22,507	22,023	20,892	17,962
Impact of embedded generation	(140)	(140)	(10)	(10)
Impact of CDM	(1,085)	(1,055)	(1,007)	(866)
Net forecast load	21,282	20,828	19,875	17,086
2008				
Forecast before embedded generation and CDM	22,730	22,241	21,099	18,140
Impact of embedded generation	(165)	(165)	(10)	(10)
Impact of CDM	(1,239)	(1,203)	(1,150)	(988)
Net forecast load	21,326	20,873	19,939	17,142

Source: Pre-filed evidence, Exhibit A, Tab 14, Schedule 3, page 19.

Forecast peak load, before the impact of embedded generation and CDM, is based on several methods (econometric models, end-use models, customer surveys, hourly load shape analysis) and is "weather-normal", that is, the forecast assumes typical weather conditions based on data from the past 31 years.

In the hearing and in final argument, intervenors focussed on two load forecasting issues. The first related to the accuracy of Hydro One's peak load forecast and the weather normalization methodology used by the Company. The second issue concerned the amount by which weather-normalized peak load should be reduced in respect of CDM activities. None of the intervenors challenged Hydro One's adjustment for embedded generation or the economic assumptions underlying the forecast, such as forecasts of GDP, housing starts, and population growth.

9.1 WEATHER-CORRECTED FORECAST DEMAND

AMPCO noted that Hydro One's weather-corrected peak load has been less than actual peak load for each of the last eight years. On average, the actual peak exceeded the weather-adjusted peak by 438 MW per year over that period. AMPCO argued that either the process is flawed or the definition of normal weather is no longer applicable. AMPCO also noted that monthly maximum peak demand in each of the first five months of 2007, as shown in IESO publications, exceeded Hydro One's forecast.

Hydro One disagreed with the conclusion drawn by AMPCO from the eight years of data. The Company stated that weather is fundamentally unpredictable and past data shows that there can be years of consistent positive or negative differences between forecast and actual load. The Company stated that over the 20 years from 1982 to 2001 the average difference between actual and weather-adjusted monthly peak demand was just 17 MW, which Hydro One says supports its contention that its methodology is sound and unbiased.

Hydro One stated that its weather normalization methodology is consistent with the industry standard and is the most commonly used approach by electricity transmitters and distributors.

AMPCO and VECC commented on the differences between the weather-normal forecast of monthly peak demand published by the IESO and Hydro One's forecast. Forecast demand for each of the 18 months from January 2007 through June 2008 is substantially higher in the IESO forecast. Hydro One indicated that the two forecasts are based on different assumptions, approaches, and definitions that arise from the different purposes of the respective forecasts. In their arguments, AMPCO and VECC disagreed with some of the examples of differences cited by Hydro One.

AMPCO recommended that the Board direct Hydro One to set its charge determinants using the IESO's weather-normal maximum hourly demand forecast. VECC submitted that the unexplained difference between the IESO and Hydro One weather-normal forecasts is growing. However, VECC did not recommend that the Board order Hydro One to use the IESO's forecast.

Board Findings

The Board does not have sufficient evidence to agree with AMPCO's assertion that Hydro One's weather-normalized forecasts have shown a "clear and growing bias" and that the weather-normalization methodology is flawed. The Board acknowledges that Hydro One's weather-normalization method has been applied consistently over the years and is similar to the methods used by most North American utilities. The Board accepts Hydro One's weather-normal peak load forecast for 2007 and 2008 (before the effects of CDM). The Board is, however, convinced that the weather-normalization issue needs further study given the well-publicized concerns about global climate change and the apparently increased occurrence of so-called "extreme weather events" in recent years.

The Board also does not have sufficient evidence to accept AMPCO's recommendation that Hydro One use the IESO weather-normal forecast to set its rates for 2007 and 2008. The IESO forecast was not examined in the hearing in any detail, and the Board has limited understanding of the assumptions and definitions that underpin that forecast. On the surface at least, the two forecasts appear to be directed at essentially the same thing, namely weather-normalized monthly peak load. The IESO's forecasts are publicly available and apparently widely-used by electricity sector participants. Thus the Board concludes that it needs to have a much better understanding of the similarities and differences between the widely-available IESO forecast and the forecast used to set transmission rates, before it can direct the Company to adopt the IESO forecast methodology in place of its own.

Given the concerns set out in the two preceding paragraphs, the Board directs Hydro One to prepare, and to submit to the Board prior to the Company's next transmission rates case, a study of evolving weather-normalization practices of utilities and other relevant entities. The study should include a recommendation, with supporting rationale, for either retaining the current methodology or making modifications. As noted by Hydro One's counsel in final argument, the Board's current three-year business plan includes an initiative to review weather normalization methodologies. That project, which has not yet been fully defined, is intended to deal specifically with the practices of gas distributors. As such, it is not a substitute for the study that the Board is directing Hydro One to undertake.

The Board also directs Hydro One to submit a detailed comparison of its forecasting methodology and assumptions with those used by the IESO in its monthly peak load forecasts before its next rates case. That report should, to the extent possible, identify the reasons for significant differences in the two forecasts in recent years.

9.2 CDM FORECAST

Considerable hearing time was devoted to the question of how much Hydro One should reduce its estimated peak load to recognize the results of CDM activities across

Ontario. Intervenors from consumer groups submitted that Hydro One has overstated the impact of CDM for 2007 and 2008 and, therefore, the Company's peak load forecast after CDM is too low.

As shown in Table 7 above, the impact of Hydro One's proposed CDM adjustment is significant. The 12-month average peak load for each of Hydro One's charge categories is lower by approximately 5% in 2007 and 2008 due to the estimated impact of CDM. According to Hydro One, transmission rates would have to increase by 1% for every 300 MW decrease in peak load.

Hydro One's approach to the 2007 and 2008 CDM adjustment can be summarized as follows:

- The Company's peak load forecast (before embedded generation and CDM) is intended to capture the impact of natural conservation efforts that individuals and businesses undertake. According to the OPA, natural conservation "occurs when Ontarians invest in conservation on their own initiative and when the efficiency of the overall stock of equipment and appliances increases as older, less efficient stock is replaced by more efficient products mandated by Ontario's building and appliance standards."[37]

- Hydro One assumes that the government's 2007 CDM target of a reduction in peak load of 1,350 MW will be achieved. For 2008, a peak load reduction of 1,550 MW is assumed. The reductions in Table 7 are lower than these amounts reflecting the fact that Table 7 shows 12-month average peak loads, not peak load in any single month.

- Hydro One points to its success in forecasting CDM-related load reductions in 2006 as support for its forecast of the impacts in 2007 and

[37] Chief Energy Conservation Officer's 2006 Annual Report, p. 26.

> 2008. In its 2006 forecast, Hydro One reduced peak load by 675 MW for CDM. Information from the OPA suggests that program-driven CDM reductions in 2006 (i.e.. reductions not due to naturally occurring CDM) reached 635 MW by summer 2006, six per cent below Hydro One's estimate. [38]

AMPCO, CCC, SEC, and VECC took issue with several aspects of Hydro One's CDM adjustment.

First, CCC submitted that the 2007 reduction of 1,350 MW is solely based on a provincial target, one that is acknowledged by the OPA to be aggressive.

Second, several intervenors argued that Hydro One has in effect "double counted" load reductions due to natural conservation: once through its normal forecasting process and then a second time by using the full 2007 CDM target of 1,350 MW.

Third, those intervenors also argued that it is inappropriate to reduce a weather-normalized peak load forecast for demand response programs that by their nature are triggered, or become fully effective, only during periods of extreme weather.

The intervenors representing consumer groups, recommended various reductions in Hydro One's CDM adjustment. CCC recommended a reduction from 1,350 MW to 650 MW for 2007 comprised of 400 MW for the double counting of natural conservation and 250 MW for overstated results of demand response programs.

SEC argued for a 400 MW reduction for each of 2007 and 2008.

[38] The 2006 Annual Report from Ontario's Chief Energy Conservation Officer reported, at page 26, that "preliminary analysis suggests that Ontarians have reduced peak demand by 963 megawatts by summer 2006. These savings include 328 megawatts of naturally occurring conservation …" The difference in the two numbers, 635 MW, presumably is the amount of the reduction due to various CDM programs.

VECC recommended a 600 MW reduction for 2007 and a 650 MW reduction for 2008. AMPCO did not recommend a specific reduction of the CDM adjustment because its concerns about all load forecasting issues were reflected in its suggestion (referred to in section 9.1) that the Board order Hydro One to use the IESO monthly forecast.

PWU supported Hydro One's CDM adjustment. It stated that the Board should exercise caution in relying on estimates of 2006 CDM-related load reductions published by the OPA. It also argued that any adjustments are premature because the OPA is in the process of developing evaluation, measurement and verification standards for CDM programs.

Board Findings

The Board acknowledges that forecasting the impact of CDM on peak loads is not a simple task at this time. The impact and effectiveness of particular CDM programs is sometimes elusive, and hard to define with precision. Having said that, the Board is not satisfied that Hydro One's proposed CDM adjustments are appropriate. While we do not object to Hydro One starting its analysis with the provincial target of 1,350 MW for 2007, we agree with intervenors that Hydro One has double counted the impact of natural conservation. It is clear from the evidence that the OPA intends to count natural conservation in determining if the 2007 target of 1,350 MW has been met.[39] Hydro One testified that its forecast, before the CDM adjustment, already factors in natural conservation. Therefore, the Board fails to understand how Hydro One can rationalize not reducing the 1,350 MW target for estimated natural conservation.

The Board also agrees with the consumer group intervenors with respect to the impact of demand response programs. Hydro One's base forecast is weather-normal, which means that extreme weather events are excluded. It would seem logical to reduce the

[39] This is particularly clear from OPA comments submitted by AMPCO on May 24, 2007 in response to Undertaking K10.3.

impact of demand response programs, which are most effective in extreme weather situations, when adjusting a weather-normal forecast.

The Board finds that Hydro One should reduce the expected impact of CDM on total Ontario peak demand by 350 MW. This adjustment is intended to address both the natural conservation and demand response issues discussed above. The Board acknowledges that this reduction is probably at the low end of an acceptable range given that it is only marginally above the 328 MW of natural conservation for 2006 referred to in the Chief Energy Conservation Officer's 2006 annual report. The Board finds there is sufficient data to support a reduction of 350 MW but also finds there is not enough reliable data to support a larger reduction as advocated by some intervenors.

The Board directs Hydro One to recalculate the average monthly forecast peak load for each charge determinant category for 2007 and 2008 based on Ontario peak load reductions of 1,000 MW in 2007 and 1,200 MW in 2008.

CDM adjustments were also addressed in Hydro One's last distribution rates case. The Decision in that case stated: "The Board was dissatisfied with the clarity and precision of the determination of the forecast CDM and expects Hydro One to provide a more sound analysis of CDM program details and reduction objectives in future applications[40]." The Board recognizes that Hydro One's transmission application was filed not long after those comments were made. It would be unfair to expect Hydro One to have rectified all of the issues identified in the distribution case. The Board does expect, however, that the CDM adjustments to the load forecast included in Hydro One's next transmission filing will be based on a much more rigorous analysis, including, where possible, load impacts attributable to specific programs.

[40] Decision With Reasons, RP-2005-0020/EB-2005-0378, April 12, 2006, para. 2.3.9.

10. CHARGE DETERMINANTS

Hydro One proposed to continue with the status quo charge determinants for its Network, Line Connection, and Transformation Connection services. The connection-related charge determinants were settled leaving only the Network determinants as an issue. AMPCO was the only intervenor with a particular interest in changing the Network charge determinants. It submitted evidence and presented a witness panel.

The current Network charge determinant, which was approved by the Board in 2000,[41] is the higher of (i) a customer's demand in kW in the hour during a month that overall system demand is at its peak (coincident peak), and (ii) 85% of the customer's peak demand during the period 7:00 am to 7:00 pm on weekdays that are not holidays (non-coincident peak). The current charge for Network service is $2.83 per kW per month.

Before it filed its application, Hydro One consulted with stakeholders about rate design options and possible changes to charge determinants. Its application described two alternatives for the Network charge determinant that it said received the most consideration. Those were coincident peak only (that is, elimination of the 85% of non-coincident peak aspect of the calculation), and coincident demand in the hours when the system peak exceeds 90% of the monthly system peak demand. Hydro One concluded that the status quo was superior to the alternatives when judged against the following criteria – cost causality, electricity market benefits, revenue stability/security, cost shifting, alignment with precedents, and implementation issues.

Provided its revenue requirement is protected in some fashion, Hydro One should be financially neutral regardless of the charge determinant selected. But changing charge

[41] Decision With Reasons, RP-1999-0044, May 26, 2000.

determinants could shift, possibly by material amounts, transmission charges incurred by individual customers or customer groups.

AMPCO's Proposal

In its evidence, AMPCO proposed that the Network charge determinant should be a customer's peak demand during the hour when system peak demand occurs in the five months of January, February, June, July and August. This method was referred as a "five-coincident-peak" approach (5-CP). AMPCO indicated that a similar method is used by transmission owners in the PJM Interconnection in the United States, where some of AMPCO's members operate manufacturing facilities.

In its final argument, AMPCO modified its proposal to some extent and recommended that the Board direct Hydro One to do three things:

- Eliminate the second element of the current Network charge determinant (85% of non-coincident peak demand, referred to by AMPCO as the "85% ratchet").

- Work with the IESO, OPA and stakeholders to define those peak demand months of the year that are of concern to system planners, operators, and Hydro One in terms of system reliability, adequacy of supply, and the need for future peaking supply. AMPCO proposed there would be just five or six such months.

- Develop an appropriate non-ratcheted charge determinant based on the identified peak months.

In its evidence, AMPCO proposed a "balancing account" for Hydro One to mitigate the risk of revenue instability due to elimination of the "85% ratchet." Its witnesses stated that AMPCO had not yet developed the details of how to calculate the revenue differences to be included in the account.

AMPCO's rationale for changing the Network charge determinant is that the current design "is incorrect in principle and constitutes a barrier to demand response and the efficient use of the transmission system.[42]" It submitted that the 85% ratchet is inconsistent with practices in other jurisdictions. In AMPCO's view, the "ratchet" reduces (by 85%) a transmission customer's incentive to control its demand during system peak hours. AMPCO submitted few large power consumers can shift all of their consumption away from the peak weekday hours from 7:00 am to 7:00 pm. Even if such consumers shifted load away from the individual peak hour, they will only receive a 15% reduction in their network transmission charges. AMPCO also suggested that it is inappropriate to charge consumers for Network service every month of the year when total demand in many months is not material from a system planning and operational standpoint.

AMPCO asserted that its approach would increase demand response during peak periods, which would be consistent with Ontario government policy, and would reduce electricity costs for all consumers.

Opposition to AMPCO's Proposal

AMPCO's proposal was opposed by Hydro One and all intervenors who commented on the issue (CCC, EDA, IESO, SEC, Toronto Hydro-Electric System, and VECC). The intervenors submitted several criticisms of AMPCO's proposal; some of the significant criticisms are summarized below.

Intervenors argued that AMPCO presented no evidence that its proposal would avoid or defer capital spending on the transmission system. VECC noted that much of the anticipated capital expenditures on the transmission system in the near term, such as

[42] AMPCO Final Argument, p. 27.

the Bruce to Milton line, are driven by new generation projects or local area load constraints, not system-wide capacity issues.

EDA noted that in the decision which set the current charge determinants (RP-1999-0044) the Board stated:

> A rate design aimed at customer demand reduction during the system's coincident peak hours would meet the test of economic efficiency, but only if the network transmission system is generally capacity-constrained. This is not the case for the OHNC [Hydro One] network transmission system either today or in the foreseeable future. (paragraph 3.4.27)

EDA submitted that AMPCO did not provide any evidence that Hydro One's system is capacity constrained now. EDA argued that the Board's finding in RP-1999-0044 remains sound. Hydro One confirmed that the transmission system is generally not capacity constrained.

EDA suggested that the AMPCO proposal would benefit only those transmission customers with the ability to shift consumption away from the peak hours. Toronto Hydro pointed out that it and other local distribution companies (LDCs) have little or no ability to shift their demand away from the peak because LDCs have little control over when their customers consume power. They would, therefore, pay a larger share of Hydro One's Network charges.

AMPCO provided little evidence that its 5-CP method would lead even its own members to shift their demand significantly. From the evidence, it appears that only steel companies have the operational flexibility to shift a significant amount of load off peak.

AMPCO provided no evidence that its proposal would lower commodity costs for the benefit of all electricity consumers even if it is assumed that it would result in significant load shifting by large industrial and commercial consumers. VECC noted Hydro One submitted data for 2005 showing that high-priced hours in the IESO-administered electricity market were poorly correlated with transmission system peak hours. If this relationship cannot be established, the “benefits” associated with the AMPCO proposal become elusive.

AMPCO filed a 2003 Navigant Consulting study, *A Blueprint for Demand Response in Ontario*, as support for its views on the commodity price impact of its proposal. VECC submitted that the study’s conclusions on the value of demand response did not support AMPCO’s premise, in part because Navigant Consulting estimated the impact of demand response for many more hours than would be relevant under AMPCO’s 5-CP proposal. A further concern was that the study was prepared several years ago when there were few organized demand response programs in Ontario. AMPCO acknowledged that a more current study would be helpful and that “it may be that a lot of the commodity savings that Navigant talked about have been mined.”[43]

EDA submitted that AMPCO’s proposal is more complex than the status quo and noted that it is unclear how the proposed “balancing account” would work. The IESO, which is responsible for billing transmission charges for all transmitters, indicated that AMPCO’s 5-CP proposal would take a minimum of six months and cost $150,000 to make the required information system changes.

During the hearing, Board staff noted that days defined a holidays by the IESO (which calculates Network transmission charges) differ from the days defined as holidays by the Board for purposes of its Regulated Price Plan. The IESO suggested that the best approach would be to have Board staff work with the IESO to implement a consistent holiday schedule.

Board Findings

The Board finds that Hydro One should continue to charge for its Network service using its current charge determinant. It does not accept AMPCO’s recommendation that the

[43] Tr. Vol. 10, p. 142.

Board should order Hydro One to work with the IESO, OPA and other stakeholders to design a new method.

AMPCO's 5-CP proposal was not well defined and, as became evident during cross examination of its witnesses, it appeared the proposal was really more of a concept than a workable alternative to the status quo. More fundamentally, the Board is not convinced that AMPCO has made a compelling case either that the current Network charge determinant has significant defects or that its 5-CP proposal is superior.

In reaching these conclusions, the Board is not saying that it is impossible to improve on the current methodology, nor is it saying that it is not open to considering changes in the future. As the Board knows from RP-1999-0044, the proceeding in which the current approach to the Network service charge determinants was approved, designing transmission rate structures requires considerable evidence and the involvement of a wide range of stakeholders. Parties that advocate changes in how customers should pay for transmission service need to submit a strong case for change, with detailed evidence and analyses showing why the status quo has undesirable effects and is inappropriate. In the Board's view, AMPCO did not put forward that case in this proceeding.

With respect to achieving a consistent definition of "holiday," the Board agrees with the IESO that the issue need not be resolved in this proceeding. It is more appropriate for Board staff to work with the IESO to implement a consistent holiday schedule.

11. IMPLEMENTATION AND COST AWARDS

Hydro One applied for a transmission revenue requirement of $1,240 million for the 2007 test year and $1,277 million for the 2008 test year. The Board made a number of findings that will affect these amounts.

During the course of the oral hearing, Hydro One provided two options for transmission rate implementation.

Option 1, is a proposal for a single uniform transmission rate change on November 1, 2007, covering a 14 month period, including:

- An RDDA amount consisting of: [Approved 2007 Revenue Requirement x 10 month forecast volume/ forecast annual volume] **less** [2000 Rates x 10 month volume], *(revenue share adjustment is not mentioned).*
- 2007 approved revenue requirement for 2 months in 2007 (Nov. and Dec.)
- 2008 approved revenue requirement for 12 months in 2008.

Option 2, is a proposal for two rate changes, one on November 1, 2007 and one on January 1, 2008.

As noted in Chapter 8, the Board finds that a single rate change (Option 1) should be implemented by Hydro One.

Therefore the Board directs the Company to file with the Board and all intervenors of record, a draft exhibit outlining the final revenue requirements and charge determinants to reflect the Board's findings in this decision. The Company should file this exhibit within 10 days of the issuance of this decision. In addition, an exhibit should be filed which includes the calculation of the uniform transmission rates, charge determinants and revenue shares resulting from this decision. This exhibit will be used in the uniform transmission rates proceeding to establish the Ontario Uniform Transmission Rates.

Hydro One should provide a clear explanation of all calculations and assumptions used in deriving the amounts used in these exhibits. Intervenors shall have 10 calendar days to respond to the Company's exhibit. The Company should respond as soon as possible to any comments by intervenors.

Cost Awards

A number of intervenors were deemed eligible for cost awards in this proceeding. On June 26, 2007, Procedural Order No. 5 was issued directing those intervenors to file their cost claims with the Board by July 10, 2007. Hydro One was to reply to those claims by July 23, 2007 and any intervenor reply to Hydro One's submissions was to be submitted by August 1, 2007.

The following eligible intervenors requested recovery of their costs and filed cost statements: Energy Probe, VECC, CCC, SEC, Electricity Distributors Association ("EDA"), and AMPCO.

Hydro One did not comment on the cost claims submitted by the eligible intervenors.

The Board wishes to commend all intervenors for coordinating their cross-examination, which resulted in efficiencies with no perceived compromise in effectiveness. The Board awards all eligible parties (Energy Probe, VECC, EDA, CCC, AMPCO and SEC) 100 percent of their reasonably incurred costs. The precise amounts will be confirmed after a review by the Board's Cost Assessment Officer to ensure that the rates or fees claimed and disbursements do not exceed the Board's guidelines contained in the Practice Directions. Hydro One shall pay the amounts of the intervenor cost awards immediately upon receipt of the Board's cost orders.

Hydro One shall also pay the Board's costs upon receipt of the Board's invoice.

DATED at Toronto August 16, 2007.

Original signed by

Pamela Nowina
Vice Chair, Presiding Member

Original signed by

Paul Sommerville
Member

Original signed by

Bill Rupert
Member

APPENDIX 1

HYDRO ONE NETWORK INC.
2007 AND 2008 ELECTRICITY TRANSMISSION RATES

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0501

PROCEDURAL DETAILS
INCLUDING LISTS OF PARTIES AND WITNESSES

August 16, 2007

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

THE PROCEEDING

On October 17, 2006, the Board issued a Letter of Direction and Notice of Application to Hydro One Networks Inc.

The Board issued Procedural Order No.1 on November 30, 2006, establishing the procedural schedule for a number of early events prior to the oral hearing. These events included an Issues Conference on December 7, 2006, and an Issues Day on December 14, 2006;

On Issues Day, the Board heard submissions from the SEC, CCC, VECC, PWU and AMPCO.

The Board issued Procedural Order No. 2 on December 20, 2006, which included the Board's decision on the contested issues identified on Issues Day. The Issues List for the proceeding was attached to Procedural Order No. 2. The Board also directed that notice be given to all transmitters and their customers, informing them that this proceeding would deal with the issue of charge determinants. Procedural Order No. 2 also included Schedule 1, consisting of excerpts of certain findings and observations from the Distribution decision (RP-2005-0020/EB-2005-0378). A number of hearing event dates were also amended:

- Written interrogatories to the Applicant by Board staff due on December 21, 2006 and by the intervenors due on January 11, 2007;
- Written interrogatory responses from the Applicant due by January 29, 2007;
- Intervenor evidence filed by February 14, 2007; interrogatories on this evidence by February 23, 2007 and responses due on March 2, 2007;
- Applicant evidence update on February 23, 2007 with a related technical conference on the update on March 6, 2007;

- A Settlement Conference was set for March 26, 2007 and the Settlement Proposal Hearing set for April 10, 2007;
- The oral hearing set to begin on April 19, 2007.

The Board issued Procedural Order No.3 on March 2, 2007, amending the start date for the oral hearing to April 23, 2007.

In a letter dated February 14, 2007 Hydro One requested that a 2007 revenue deficiency deferral account be established beginning January 1, 2007 to record the revenue deficiency between the approved revenue for 2007 and the forecast revenues at currently approved transmission rates. Hydro One requested a decision from the Board on this issue by March 31, 2007. The Board issued Procedural Order No. 4 on March 12, 2007 inviting intervenors to make submissions on this request.

On March 30, 2007, the Board issued a Partial Decision and Order approving the establishment of the 2007 revenue deficiency deferral account.

The Settlement Conference was held on March 26, 2007 and on April 3, 2007 the Settlement Proposal was filed with the Board and was the subject of the Settlement Proposal hearing held on April 10, 2007. The Board issued its Settlement Decision on April 18, 2007.

The oral hearing began on April 23, 2007 and concluded on June 13, 2007.

Procedural Order No. 5 was issued on June 26, 2007 regarding submission of cost claims by eligible intervenors.

PARTICIPANTS AND REPRESENTATIVES

Below is a list of participants and their representatives who were active either at the oral hearing or at another stage of the proceeding. A complete list of intervenors is available at the Board’s offices.

Board Counsel and Staff	Donna Campbell Jennifer Lea Harold Thiessen Nabih Mikhail Chris Cincar Wade Frost Martin Davies
Hydro One Networks Inc.	Don Rogers Joe Toneguzzo
Society of Energy Professionals	Richard Long Sonia Pylyshyn
IESO	David Short
Consumers Council of Canada	Robert Warren Julie Girvan
Ontario Power Generation	Tony Petrella
Association of Major Power Consumers of Ontario	Mark Rodger Wayne Clark
Energy Probe	David MacIntosh Tom Adams
School Energy Coalition	John De Vellis
Vulnerable Energy Consumer's Coalition	Michael Buonaguro Bill Harper
Power Workers Union	Richard Stephenson

WITNESSES

There were 20 witnesses who testified at the oral hearing.

The following Company employees appeared as witnesses at the oral hearing:

Frank Jacob	Manager, Program Integration and Regulatory Filing
Mike Penstone	Director, System Investment
George Carleton	Director, Supply Chain Services, Finance
Andy Stenning	Director, Station Maintenance

Naren Pattani	Manager, Transmission System Development
Nairn McQueen	Vice President, Engineering and Construction Services
Paul Tremblay	Director, Network Operating, Grid Operations
Judy McKellar	Director, Human Resources
Sandy Struthers	Chief Information Officer
Greg Van Dusen	Director, Business Integration
Ian Innis	Director, Corporate Planning and Regulatory Finance
William Paolucci	Assistant Treasurer, Treasury Division
Andy Poray	Director, Regulatory Policy and Support
Stanley But	Manager, Economics and Load Forecasting
Henry Andre	Manager, Regulatory Affairs, Corporate Regulatory Affairs

In addition, the Company called the following witness:

Kathleen McShane	President and Senior Consultant, Foster Associates Inc.

Witnesses called by intervenors:

For AMPCO:

Wayne Clark	Consultant, SanZoe Consulting, Inc.
Darren MacDonald	Director of Energy, Gerdau Ameristeel
Gary Saleba	President and CEO, EES Consulting

For VECC/CCC:

Dr. Laurence D. Booth	CIT Chair, Structured Finance, Rotman School of Management, University of Toronto

In addition, evidence was filed by York University professors Dr. Fred Lazar and Dr. Eli Prisman on behalf of Board staff. Drs. Lazar and Prisman did not appear as witnesses in the oral hearing.

APPENDIX 2

HYDRO ONE NETWORK INC.
2007 AND 2008 ELECTRICITY TRANSMISSION RATES

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0501

SETTLEMENT PROPOSAL

August 16, 2007

Hydro One Networks Inc.
Test Year 2007/2008 Transmission Rates
EB-2006-0501

SETTLEMENT PROPOSAL

Preamble:

This settlement proposal is filed with the Ontario Energy Board ("the Board") in connection with the application by Hydro One Networks for an Order or Orders approving the revenue requirement and customer rates for the transmission of electricity to be implemented in 2007.

Further to the Board's Procedural Order No. 2 dated December 20, 2006, a settlement conference was held on March 26 and 27, 2007 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* ("Rules") and the Board's Settlement Conference Guidelines ("Guidelines").

Hydro One Networks and the following intervenors ("the parties") participated in the settlement conference:

Association of Major Power Consumers in Ontario ("AMPCO")
Consumers Council of Canada ("CCC")
Electrical Distributors Association (EDA)
Energy Probe Research Foundation ("Energy Probe")
Independent Electricity System Operator ("IESO")
Ontario Power Generation ("OPG")
Power Workers' Union ("PWU")
School Energy Coalition ("SEC")
Society of Energy Professionals (SEP)
Vulnerable Energy Consumers Coalition ("VECC")

Ontario Energy Board staff also participated in the settlement conference but are not party to this settlement proposal.

Outlined below are the positions of the parties following the settlement conference. The settlement proposal follows the format of the Approved Issues List for ease of reference. The issues are characterized as follows:

Settled: If the settlement proposal is accepted by the Board, the parties will not adduce any oral evidence during the hearing as the applicant and the intervenors who take any position on the issue agree to the proposed settlement.

Partially Settled: If the settlement proposal is accepted by the Board, the parties will only adduce evidence on portions of the issues as the applicant and the intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue.

Not Settled: The applicant and the intervenors who take a position on the issue will adduce evidence at the hearing on the issue as the parties were unable to reach agreement.

For ease of reference, the following outlines the status of the issues as outlined in the settlement proposal:

Settled: Issue completely resolved. Parties will not adduce evidence at the hearing.	**Partially Settled:** Issue partially resolved. Parties will adduce evidence at hearing on certain portions of the issue.	**Not Settled:** Issue not resolved. Evidence to be adduced on entirety of issue.
# issues settled: 24	# issues partially settled: 2	# issues not settled: 14

The positions taken by the various parties on each of the settled or partially settled issues are identified throughout the settlement proposal.

The settlement proposal provides a brief description of each of the settled and partially settled issues, together with references to the evidence filed to date. The parties to the settlement proposal agree that the evidence filed to date in respect of each settled or partially settled issue supports the proposed settlement. In addition, the parties agree that the evidence filed in support of each settled or partially settled issue contains sufficient detail, rationale and quality information to allow the Board to make findings in keeping with the settlement or partial settlement reached.

The settlement of issues 8.1 and 8.2 are proposed as a package. The balance of the issues in the settlement proposal are not proposed to the Board as a package settlement. As such, the parties acknowledge that the Board may accept settlement on any individual issue, or combination of them.

1. ADMINISTRATION (Exhibit A)

1.1 Are the Affiliate Service Agreements still cost effective and efficient in delivering services? Have any changes occurred in these arrangements since the 2006 distribution rates proceeding (RP-2005-0020/EB-2005-0378)? (A1/T8/S2)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

A-8-2 Affiliate Service Agreements

J-1-1, J-1-2, J-1-3, J-5-1, J-5-2, J-5-3, J-5-4, J-5-5, J-5-6, J-9-36, J-9-37, J-9-38

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

1.2 Has Hydro One addressed all relevant Board directions from previous proceedings? (A/T17/S1)

Settled. The parties accept the Applicant's position on this issue, as it was agreed that the following matters, for which agreement could not be reached, would be addressed in the context of other issues. The particulars are outlined below.

a) Intervenors are concerned about Hydro One's interpretation of the Board's RP-2005-0501 Decision, which established an Earnings Sharing Mechanism, including the appropriateness of prior year adjustments being made to the 2006 Earnings/Sharing calculation.

The parties agreed this concern would be dealt with as part of the Board's consideration of issue 9.1.

b) Intervenors are concerned about the accuracy of the Net Income amount proposed by Hydro One for the Transmission Earning/Sharing mechanism.

The parties agreed this concern would be dealt with as part of the Board's consideration of issue 9.1.

c) Is Hydro One's proposal to apply the Earnings/Sharing amount as contributed capital appropriate?

The parties agreed this concern would be dealt with as part of the Board's consideration of issue 9.1.

d) Intervenors raised a concern relating to the justification for the Niagara Reinforcement Project

The parties agreed this concern would be dealt with as part of the Board's consideration of issue 3.4. However, the parties were unable to reach agreement on intervenors' concerns relating to the economic justification of the Niagara Reinforcement Project.

e.) Intervenors, except the SEP, raised a concern regarding whether the Company has complied with the following directives, relating to compensation issues, given by the Board in its Decision with Reasons dated April 12, 2006 in EB-2005-0378: "the Board expects Hydro One to identify what steps the company has taken or will take to reduce labour rates." [para. 3.4.4]; and, "The Board expects Hydro One to file appropriate evidence in the next main rates case to establish that none of the incentive compensation should be charged to the shareholder." [para. 3.4.7]

The parties, except the SEP, agreed this concern would be dealt with as part of the Board's consideration of issue 2.2.

Evidence:

Exhibit A-17-1, Table 1 (entitled Board Directives from Proceeding RP-1998-0001) identifies the reference exhibit which contains Hydro Ones response to the related directives.

Supporting Parties: AMPCO, CCC, Energy Probe. PWU, SEC, SEP (with the exception that the SEP requested to be excluded from comments in 1.2e), VECC

Parties taking no position: EDA, IESO, OPG,

1.3 <u>Is the proposal to establish a revenue requirement beyond the 2007 and 2008 test years without a separate cost of service approval appropriate?</u>

Not settled. The parties were unable to reach agreement on this issue.

1.4 <u>Is the proposed methodology to establish the future revenue requirement beyond 2007 and 2008 appropriate?</u>

Not settled. The parties were unable to reach agreement on this issue.

1.5 Is the proposal to include capital spending as incurred in Rate Base for 2009-2010 appropriate? (A1/T13/S1)

Not settled. The parties were unable to resolve this issue.

1.6 Are Hydro One's Economic and Business Planning Assumptions for 2007 and 2008 appropriate?

Settled. Intervenors had no concerns with respect to Hydro One's economic and business planning assumptions for 2007 and 2008, except for the assumed interest rates regarding cost of capital. The parties agreed that business and economic planning assumptions utilized by Hydro One for 2007 and 2008 are appropriate.

The parties agreed that concerns regarding Hydro One's interest rates assumptions as they affect cost of capital would be addressed under issue 4.2.

Evidence:

A-9-1 Hydro One Transmission Financial Statements for the Year Ended 2005

A-10-1 Hydro One Inc. – Historic Year Annual Reports

A-10-2 Hydro One Inc. – Budget Year Quarterly Reports

A-14-1 Planning Process

A-14-2 Economic Indicators

A-14-4 Project and Program Approval and Control

J-1-15, J-1-16, J-1-17, J-5-26, J-10-1, J-10-2, J-10-3, J-10-4

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, PWU, SEC, SEP, VECC

Parties taking no position: EDA, OPG

2. COST OF SERVICE (Exhibit C)

2.1 Are the overall levels of the 2007 and 2008 Operation, Maintenance and Administration Budgets appropriate? (C1/T1/S1)

Not settled. The parties were unable to reach agreement on this issue.

2.2 Is the 2007 and 2008 budget for Human Resources related costs (wages, salaries, benefits, incentive payments and pension costs) including employee levels, appropriate? (C1/T3/S1&2)

Not settled. The parties were unable to reach agreement on this issue.

2.3 Is the proposed level of corporate O&M costs allocated to the transmission business for 2007 and 2008 appropriate and in line with the O&M cost allocation approved by the Board in Hydro One's 2006 distribution proceeding (RP-2005-0020/EB-2005-0378)? (C1/T5/S1&2)

Settled. The parties accept the Applicant's position on this issue.

The methodology for allocation of costs, for purposes of setting 2007 and 2008 rates, has been accepted, subject to impacts of Hydro One's Human Resource related costs which is an unsettled issue (Issue #2.2).

Evidence:

C1-5-1 Common Corporate Cost Allocation and Cost Allocation Methodology

J-1-29, J-1-42, J-1-43, J-1-44, J-1-45, J-1-46, J-1-47, J-1-48, J-1-49, J-1-99, J-5-65, J-5-66, J-5-67, J-5-68, J-5-69, J-9-36, J-9-37, J-10-8

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

2.4 Is Hydro One's depreciation expense appropriate for 2007 and 2008 and in line with the depreciation methodology approved by the Board in Hydro One's 2006 distribution application (RP-2005-0020/EB-2005-0378)? (C1/T6/S1&2)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

C1-6-1 Depreciation and Amortization Expenses

C1-6-2 Depreciation Rate Review

C2-5-1 Depreciation and Amortization Expenses

J-1-50, J-5-70, J-9-54

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

2.5 Is Hydro One's proposed transmission overhead capitalization rate appropriate? (C1/T5/S2)

Settled. The parties accept the Applicant's proposed overhead capitalization rate.

Evidence:

C1-5-2 Overhead Capitalization Rate

J-1-51, J-1-52, J-1-53 (overlap with issue 3.3), J-1-54, J-1-77ii, J-5-71

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

2.6 Are the amounts proposed to be included in 2007 and 2008 revenue requirements for capital and property taxes appropriate? (C2/T4/S1)

Settled. The parties accept the Applicant's position on this issue.

Note the Capital Tax amount for 2006 is currently under review and will be revised subject to finalization of results and audit review. Audited Transmission Financial statements will be filed when available during the hearing. Hydro One commits to filing an update of 2006 capital taxes using the audited 2006 financial statements.

Evidence:

C2-4-1 Capital Taxes

C1-2-6 Property Taxes

J-1-55, J-1-56, J-1-57, J-1-58, J-5-72, J-7-23

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

2.7 Is the amount proposed to be included in 2007 and 2008 revenue requirements for income taxes, including the methodology, appropriate? (C1/T7/S1)

Settled. The parties accept the Applicant's position on this issue.

Additional information was provided during the Settlement process. It was agreed that the 2007 Federal and Provincial Budgets will not have a material impact on HONI's revenue requirement in 2007. Any impacts arising from those budgets will be captured in the proposed Tax Rate Changes Variance Account.

Evidence:

C1-7-1 Payments in Lieu of Corporate Income Taxes

C2-6-1 Calculation of Utility Income Taxes

J-1-59, J-1-60, J-1-62

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

3. RATE BASE (Exhibit D)

3.1 Are the amounts proposed for the 2007 and 2008 Rate Base appropriate? (D1/T1/S1)

Partially Settled. The parties have agreed that the proposed amounts for the 2007 and 2008 rate base are appropriate, except for the amounts proposed for capital expenditures in 2007 and 2008 to be dealt with under issue 3.2. Rate base will be modified to reflect any subsequent changes to capital expenditures in 2007 and 2008 resulting from the resolution of issue 3.2.

During the Settlement Conference, additional information was provided that deals with $7.3M of OEFC owned assets in Hydro One's rate base[1].

Evidence:

D1-1-1 Rate Base

D1-1-3 Level and Appropriateness of Transmission Assets

D2-1-1 Statement of Utility Rate Base

J-1-58, J-1-63, J-1-64, J-1-65, J-5-73

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

3.2 Are the amounts proposed for Capital Expenditures in 2007 and 2008 appropriate? (D1/T3/S1&3)

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[1] Hydro One made payment for these assets as part of the settlement for the acquisition of assets from Ontario Hydro.

Due to jurisdictional issues and due to the fact that underlying land permits did not allow assignment without federal governmental consent, assets owned by Ontario Hydro on Reserves did not pass to HONI under the transfer orders. Instead, these were held by OEFC, as the continuation of Ontario Hydro, in trust for HONI. Pursuant to an Indemnity and Trust Agreement between OEFC and HONI, it is clear that OFEC is merely holding these assets in trust for HONI as the beneficial owner. HONI has all of the operational responsibility for the assets and has indemnified OEFC completely and comprehensively from any and all liabilities and responsibilities arising from the assets, or the underlying permits.

Not settled. The parties were unable to reach agreement on this issue.

3.3 Is Hydro One's corporate asset allocation for the transmission business in line with the common capital and common asset allocation approved by the Board in Hydro One's 2006 distribution application (RP-2005-0020/EB-2005-0378)? (C1/T5/S3) (D1/T3/S5)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

C1-5-3 Common Asset Allocation

J-1-53 (overlap with issue 2.5), J-1-99, J-5-91

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

3.4 Is the proposed inclusion of "Supply Mix" Capital Project expenditures in 2007 and 2008 Rate Base as they are incurred, appropriate? (D1/T1/S4)

Not settled. The parties were unable to reach agreement on this issue.

In addition, the parties were unable to reach agreement on intervenors' concerns relating to the economic justification of the Niagara Reinforcement Project (from issue 1.2).

3.5 Is the submitted Lead Lag study appropriate for the development of the Working Capital component of the Rate Base? (D1/T1/S5)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

D1-1-5 Working Capital and Lead/Lag Study

J-1-63, J-1-104, J-5-94, J-7-28

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

3.6 Does the Asset Condition Assessment adequately address the current condition of the transmission system assets and the determination of capital needs of the system in the future? (D1/T2/S1)

Settled. The parties accept the adequacy of the Applicant's Asset Condition Assessment but without prejudice to their position on capital spending levels.

Evidence:

D1-2-1 Asset Condition Study

J-1-105, J-1-106, J-3-4, J-5-29, J-5-31, J-5-34, J-5-77, J-5-95, J-5-96, J-5-97, J-5-98, J-6-2

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

3.7 Is the method that Hydro One has used to calculate AFUDC appropriate? (D1/T4/S1)

Settled. Hydro One has agreed that the AFUDC will be calculated using the rate approved by the Board for distribution companies, to be effective January 1, 2007.

Evidence:

D1-4-1 Allowance for Funds Used During Construction

J-1-68, J-1-69

Supporting Parties: AMPCO, CCC, Energy Probe, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG, PWU ("not opposed")

4. COST OF CAPITAL/CAPITAL STRUCTURE (Exhibit B)

4.1 What is the appropriate Capital Structure for Hydro One Networks' transmission business for the 2007 and 2008 test years? (B1/T1/S1) (B1/T3/S2)

Not settled. The parties were unable to reach agreement on this issue.

4.2 What is the appropriate Return on Equity (ROE) for Hydro One Networks' transmission business for the 2007 and 2008 test years? (B1/T1/S1) (B1/T3/S2)

Not settled. The parties were not able to reach agreement on this issue.

4.3 Are Hydro One's proposed costs for its debt and preference share components of its capital structure appropriate? (B1/T2/S1)

Not settled. The parties were not able to reach agreement on this issue.

4.4 Should the Capital Structure, Capital Costs and Rate of Return on Equity vary between Hydro One's distribution and transmission businesses? (B1/T3/S1)

Not settled. The parties were unable to reach agreement on this issue.

5. REVENUE REQUIREMENT (Exhibit E)

5.1 Is the proposed amount for 2007 and 2008 External Revenues, including the methodology used to cost and price these services, appropriate? (E3/T1/S1)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

E3-1-1 External Revenues

J-5-104, J-5-105, J-7-41, J-7-42, J-7-43

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

6. COST ALLOCATION (Exhibit G)

6.1 Are Hydro One's proposed cost pools appropriate and have the costs assigned to these pools been allocated appropriately? (G1/T1-6)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

G1-1-1 Cost Allocation and Charge Determinants

G1-2-1 Description of Cost Allocation Methodology

G1-3-1 Network and Line Connection Pools

G1-4-1 Transformation Connection Pool

G1-5-1 Wholesale Meter Pool

G1-6-1 Cost Data for Low Voltage Switchgear Compensation

G2-5-1 Detailed Revenue Requirement by Rate Pool

H1-5-3 Disposition of Export Transmission Service Revenues

J-1-4, J-1-136, J-1-138, J-5-106, J-5-107, J-5-108, J-5-109, J-5-110, J-5-111, J-5-112, J-5-113, J-5-114, J-5-115, J-5-123, J-8-4

AMPCO Evidence, Testimony of Gary S. Saleba, Pg. 11 Line 16-18

J-13-1 (Pg.2 under the heading "Hydro One Cost Allocation")

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, OPG, PWU, SEC, SEP, VECC

Parties taking no position: EDA

6.2 Is the proposed cost allocation treatment of "dual function" lines appropriate? (G2/T2/S1)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

G1-2-1 Description of Cost Allocation Methodology

G1-3-1 Network and Line Connection Pools

G2-2-1 Allocation Factors for Dual Function Lines

G2-4-1 Asset Value by Functional Category

G2-4-2 Total Depreciation by Functional Category

G2-4-3 Return on Capital and Income Taxes by Functional Category

G2-4-4 OM&A Costs by Functional Category

J-5-107, J-5-108, J-5-109, J-5-111, J-5-114, J-5-115,

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

6.3 <u>Is it appropriate to create a Wholesale Meter pool and was the establishment of this pool done appropriately? (G1/T5/S1)</u>

Settled. The parties accept the Applicant's position on this issue.

Evidence:

G1-2-1 Description of Cost Allocation Methodology

G1-5-1 Wholesale Meter Pool

G2-5-1 Detailed Revenue Requirement by Rate Pool

J-5-107, J-5-111

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, OPG, PWU, SEC, SEP, VECC

Parties taking no position: EDA

6.4 <u>Should the customers directly connected to Network Stations that do not pay Line Connection Charges pay them and if so, what mechanism should be used? (G1/T3/S1)</u>

Settled. The parties agreed to resolve this issue and agree that the status quo is appropriate for this case. Hydro One has undertaken to conduct an internal study on connection facilities terminating in Network Stations and associated connection charges to be submitted as part of the next transmission rate application.

Evidence:

G1-3-1 Network and Line Connection Pools

J-1-137

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

6.5 To what cost pools should "Local Loops" be allocated? (G1/T3/S1)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

G1-3-1 Network and Line Connection Pools

J-1-138, J-5-115

Supporting Parties: AMPCO, CCC, Energy Probe, PWU, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG

7. RATE DESIGN and CHARGE DETERMINANTS (Exhibit H)

7.1 Is the load forecast and methodology appropriate and have the impact of Conservation and Demand Management initiatives been suitably reflected? (A1/T14/S2&3) (H1/T2/S1)

Not settled. The parties were unable to reach agreement on this issue.

7.2 Have the proposed charge determinants been forecast appropriately for each of the transmission revenue pools? (G1/T1/S1) (H1/T3/S1)

Settled. The parties accept the Applicant's position on this issue.

Evidence:

G1-1-1 Cost Allocation and Charge Determinants

H1-3-1 Charge Determinants

H1-4-1 Rates for Wholesale Meter Service

Supporting Parties: AMPCO, CCC, Energy Probe, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG, PWU ("not opposed")

7.3 Is the proposal to continue with the status quo charge determinants for Network and Connection service appropriate? (H1/T3/S1)

Partially settled. The parties were able to agree that the current charge determinants for Connection service are appropriate. The parties were unable to reach agreement on whether the current charge determinants for Network service are appropriate.

Evidence:

H1-3-1 Charge Determinants

J-5-122

Supporting Parties: AMPCO, CCC, EDA; Energy Probe, IESO, PWU, SEC, SEP, VECC

Parties taking no position: OPG

7.4 Is it appropriate to continue the Export Transmission Service Tariff and should this tariff be changed? (H1/T5/S1, 2 & 3)

Settled. The parties were able to reach agreement on this issue.

After identifying alternatives as directed by the Board, Hydro One assumed that the status quo of $1.00/MWh would continue, for the purposes of its application.

The parties have agreed that the status quo ETS tariff of $1/MWh should be maintained for the time being, but that the IESO should now be identified as the entity responsible to pursue and negotiate, with neighbouring jurisdictions, acceptable reciprocal arrangements with the intention to eliminate the ETS tariff, and study the appropriate ETS tariff, including those options identified in H1/T5/S1. The IESO will seek input from market participants and interested intervenors in this proceeding and keep the parties informed of the progress of negotiations and the study. It is agreed that the IESO will make its report available to the Board upon completion which will be no later than June 1, 2009 with the results of reciprocal arrangement negotiations and the study including recommendations for an appropriate ETS tariff. Hydro One Networks Inc. remains responsible for seeking changes to its approved transmission revenues and rates and will do so as part of the 2010 transmission rate-resetting process period, following the publishing of the study.

Evidence:

H1-5-1 Rates for Export Transmission Service

H1-5-2 Review of Export Tariffs in Other Jurisdictions

H1-5-3 Disposition of Export Transmission Service Revenues

J-1-144, J-1-145, J-1-146, J-1-147, J-1-148, J-5-106, J-5-125, J-5-126

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, OPG, SEC, SEP, VECC

Parties taking no position: EDA, PWU ("not opposed")

8. OTHER ISSUES

8.1 Is the proposal for the establishment and methodology of Hydro One's 2007 and 2008 Deferral and Variance Accounts appropriate? (F1/T3/S1)

Settled. The parties have agreed, as part of a package, to resolve this issue together with issue 8.2 as follows:

i) The amount of the Deferred Export Transmission Service Credit is $54.5M (Update).

ii) The Ontario Energy Board Cost Account will not be altered to reflect load growth.

iii) The Market Ready Cost Account will be reduced by 10%, even though it has already been reduced to reflect the OEB Distribution decision. This value after a 10% reduction is $16.7M as at April 30, 2007.

Note: The 10% reduction to principal was calculated effective December 2004 (consistent with the date of adjustments arising from the Distribution market ready decision). This amount is then interest improved to arrive at the value of $16.7M as at April 30, 2007.

iv) Interest on all variance accounts will be that approved by the Board for distribution companies, to be effective January 1, 2007.

v) All variance accounts will be cleared over four years in order to facilitate rate smoothing.

In addition, as it relates to new accounts, the parties agree that the following requested new variance accounts should be approved:

1. OEB Cost Assessment Differential
2. Tax Rate Changes
3. Transmission System Code Changes
4. Pension Cost Differential

The parties further agree to await the Board's decision on the 2007 Revenue Deficiency Deferral Account presently under reserve.

As the recent federal and provincial budgets have not been formally passed into law, any tax impacts of those budgets will be recorded in the new Tax Rate Changes Account, once formalized.

Evidence:

F1-1-1 Regulatory Assets

F1-1-2 Variances Resulting From Board Decisions

F1-2-1 Planned Disposition of Regulatory Assets

F1-3-1 Variance Account Requested

F2-1-1 Regulatory Assets

F2-1-2 Schedule of Annual Recoveries

J-1-149, J-1-150, J-1-151, J-1-152, J-1-153, J-1-154, J-1-155, J-5-19, J-5-127, J-5-128, J-5-129

Supporting Parties: AMPCO, CCC, Energy Probe, IESO (v), SEC, SEP, VECC

Parties taking no position: EDA, IESO [(i) to (iv) and new accounts], OPG, PWU ("not opposed")

8.2 Is the proposal for the amounts and disposition of Hydro One's existing Deferral and Variance Accounts (Regulatory Assets) appropriate? (F1/T1/S1)

Settled. The parties have resolved this issue as a package with issue 8.1, outlined above.

Evidence: see issue 8.1 above.

Supporting Parties: AMPCO, CCC, Energy Probe, SEC, SEP, VECC

Parties taking no position: EDA, IESO, OPG, PWU ("not opposed")

8.3 Has Hydro One delivered an adequate level of service and other performance compared with other jurisdictions and other relevant performance standards? (A1/T15/S1, 2&3)

Settled. The parties accept the Applicant's position on this issue. The parties have agreed that the issue related to customer delivery point performance standards would be addressed as part of proceeding RP-1999-0057/EB-2002-0424.

Evidence:

A-15-1 Transmission Business Performance

A-15-2 Transmission Benchmarking

A-15-3 Customer Delivery Point Performance Standards

J-1-33, J-1-35, J-1-36, J-1-38, J-1-156, J-1-157, J-1-158, J-1-159, J-1-160, J-1-161, J-1-162, J-1-163, J-1-164, J-1-166, J-2-6, J-3-1, J-3-4, J-3-5, J-5-130, J-5-131, J-5-132, J-5-133, J-5-134, J-5-135, J-5-136, J-5-137, J-6-3, J-6-4, J-7-7, J-8-5

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, OPG, PWU, SEC, SEP, VECC

Parties taking no position: EDA

8.4 Has Hydro One demonstrated the need to reinforce the existing 115kV connection lines between Leaside TS and Birch Junction TS in the city of Toronto project? (D2/T2/S3)

Settled. The parties were able to reach agreement on this issue. The parties agreed that the applicant has demonstrated the need to relieve loading on the existing 115kV connection lines between and Leaside and Birch Junction TSs.

The Applicant has agreed that the issues regarding options, alternatives and costing of the mitigating alternatives will be deferred from this rate application to be dealt with in a separate section 92 application to the Board.

Evidence:

D2-2-3 Justification for Programs or Projects in excess of $3 Million (#D18 Leaside x Birch Junction Transmission Reinforcement)

J-1-167, J-5-138

Supporting Parties: AMPCO, CCC, Energy Probe, IESO, PWU, SEC, SEP, VECC

Parties taking no position: EDA, OPG

9. RATE IMPLEMENTATION

9.1 How should the Board deal with any revenue implications regarding the Hydro One Transmission earnings/sharing mechanism (EB-2005-0501) established by the Board?

Not settled. The parties were unable to reach agreement on this issue.

Also, the parties agreed that the following concerns would be dealt with as part of the Board's consideration of issue 9.1 rather than issue 1.2.

a) Intervenors are concerned about Hydro One's interpretation of the Board's RP-2005-0501 Decision, which established an Earnings Sharing Mechanism, including the appropriateness of prior year adjustments being made to the 2006 Earnings/Sharing calculation.

b) Intervenors are concerned about the accuracy of the Net Income amount proposed by Hydro One for the Transmission Earning/Sharing mechanism.

c) Is Hydro One's proposal to apply the Earnings/Sharing amount as contributed capital appropriate?

9.2 Are the bill impacts as a result of this application for various customer groups reasonable? (A1/T2/S1)

Not settled. The parties agreed that this issue could not be resolved at this time.

APPENDIX 3

HYDRO ONE NETWORK INC.
2007 AND 2008 ELECTRICITY TRANSMISSION RATES

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0501

SETTLEMENT DECISION

August 16, 2007

Ontario Energy Board

Commission de l'Énergie de l'Ontario

EB-2006-0501

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the transmission of electricity commencing January 1, 2007.

SETTLEMENT PROPOSAL DECISION

Hydro One Networks Inc. ("Hydro One" or the "Company") filed an Application, dated September 12, 2006, with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act 1998, S.O. 1998*, c.15, Schedule B. The Board assigned file number EB-2006-0501 to the Application and issued a Notice of Application dated October 17, 2006.

On April 3, 2007, Hydro One Networks Inc. filed a Settlement Proposal that was developed and agreed to by Hydro One and ten intervenors in this proceeding. The Settlement Proposal indicates that the parties reached full settlement on 24 issues and partial settlements on two issues. There was no settlement on fourteen issues.

Hydro One presented the proposal to the Board at a settlement hearing on April 10, 2007 (together with some additional clarifying statements on settled Issues 1.2 and 6.5). Board staff made submissions on two settled issues – 8.1 and 8.2, which relate to deferral and variance accounts – and recommended that those issues be removed from the proposal.

On April 10, 2007, the Board accepted the Settlement Proposal[1] except for issues 7.4, 8.1, 8.2 and 8.4. The Board's decision on these issues is below.

Issue 7.4 – Export Transmission Service Tariff

Issue: "Is it appropriate to continue the Export Transmission Service Tariff and should this tariff be changed?"

The settlement proposal stated that the status quo of $1.00/MWh would continue. It also went on to describe agreement on the role that the IESO would take in negotiating acceptable reciprocal arrangements with neighbouring jurisdictions, studying the appropriate ETS tariff and making its report available to the Board. At the settlement hearing, the Board asked the parties to consider whether or not the issue could be settled by simply agreeing to the status quo and removing the additional discussion in the proposal on future actions by the Independent Electricity System Operator (IESO)[2].

After consulting with the settling parties, on April 11, 2007, Hydro One filed with the Board modified settlement language for this issue. Although the settlement continues to refer to possible future action by the IESO, the language makes clear that the Board is not approving the future actions of the IESO and that any change to the ETS charge must be made through a Board rates process. The settlement language is now in a form satisfactory to the Board. The Board accepts the modified settlement proposal for this issue.

Issue 8.4 – Leaside TS to Birch Junction TS Reinforcement

Issue: "Has Hydro One demonstrated the need to reinforce the existing 115kV connection lines between Leaside TS and Birch Junction TS in the City of Toronto project?"

[1] Transcript, April 10, 2007, page 91.
[2] Transcript, April 10, 2007, page 36.

The settlement proposal agreed that the need to relieve loading on the existing 115kV connection lines between Leaside TS and Birch Junction TS had been demonstrated and was accepted. The proposal also stated agreement that the issues regarding options, alternatives and costing of the mitigating alternatives will be deferred from this rate application to be dealt with in a separate section 92 application to the Board. In the oral hearing of the settlement proposal, the Board indicated that it could not accept the proposed settlement on this issue because it would mean the need for this project would not be examined on the record.[3] The Board asked Hydro One to consider two options for addressing the need for this project: moving the issue from this rates case to the Section 92 leave to construct proceeding for the project, or by having a Hydro One witness panel address the need issue as part of this rate hearing.

On April 11, 2007, Hydro One informed the Board that it will present evidence on the need to relieve loading on the existing 115kV connection lines between Leaside TS and Birch Junction TS at this hearing. The Board accepts the remainder of the settlement on this issue, being the deferral of issues on options, alternative and costing of mitigating alternatives to a section 92 application.

Issues 8.1 and 8.2 – Deferral and Variance Accounts

Issue 8.1, "Is the proposal for the establishment and methodology of Hydro One's 2007 and 2008 Deferral and Variance Accounts appropriate?"
Issue 8.2, "Is the proposal for the amounts and disposition of Hydro One's existing Deferral and Variance Accounts (Regulatory Assets) appropriate?"

At the settlement hearing, Board staff made submissions on general policy issues with respect to deferral and variance accounts being established through settlement agreements. Staff also expressed some particular concerns on the specific accounts referred to in the proposed settlement of Issue 8.1. The Board

[3] Transcript, April 10, 2007, page 80.

indicated it would consider the issues further in light of the submissions by Board staff.

Policy Issues

Board staff submitted that there are “policy dimensions to creating the variance and deferral accounts that Staff believes should be addressed on a more comprehensive basis than is permitted by the settlement process.”[4] Staff noted that its concerns extended to the disposition of account balances as well as the creation of accounts. Staff advocated that Issues 8.1 and 8.2 not be accepted by the Board as settled issues; rather, the issues should be explored in the hearing. In addition, Board staff submitted that “for policy reasons perhaps it is now the time for the Board to consider whether or not the creation of such accounts should in fact be part of a settlement proposal.”[5]

Hydro One, VECC and CCC indicated that in other rates cases the Board has accepted many settlement agreements that have dealt with deferral and variance accounts. Hydro One submitted that if the Board wishes to establish a policy that these accounts should not be considered in settlement agreements, it should seek input from larger group than just the parties in this particular rates case.

Specific Deferral and Variance Accounts

Three existing deferral accounts are covered by Issues 8.1 and 8.2. Board staff submitted that the Board should not accept the settlement because the Board should explicitly address whether the accounts were authorized, the prudence of the expenditures included in the accounts, and the disposition of the accounts.[6] Staff observed that Hydro One did not seek, and was not given, permission by

[4] Transcript, April 10, 2007, pp. 57 and 58.
[5] Transcript, April 10, 2007, page 48.
[6] Transcript, April 10, 2007, page 63.

the Board to establish one of the accounts, the Ontario Energy Board Cost Account.

None of the parties to the settlement proposal object to Hydro One establishing the following four new variance accounts: OEB Cost Assessment Differential; Tax Rate Changes; Transmission System Code Changes; and, Pension Cost Differential. Board staff submitted that the Board should reject the settlement on these accounts and, instead, should consider whether the accounts meet criteria used in the past by the Board when granting deferral and variance accounts for electricity distributors.

The settlement proposal for Issue 8.1 refers to a possible fifth new account and states: “The parties further agree to await the Board’s decision on the 2007 Revenue Deficiency Deferral account presently under reserve.” The Board understands that this language was included in error and is unnecessary given that the Board has already authorized that account in Procedural Order No. 4 issued on March 12, 2007.

Board Findings

With respect to the general policy issues raised by Board staff, the Board does not believe that this rates case is the right forum to address those issues. The Board agrees with Hydro One that if this issue is to be addressed the Board should seek input from a wider group, including parties active in the natural gas sector.

Deferral and variance accounts are used extensively by the OEB in both natural gas and electricity rates cases The OEB may want to review its regulatory agenda to determine if it should initiate a public policy process to examine the issues associated with the use of these accounts.

The Board will accept the settlement proposal for existing deferral accounts, including the four-year period over which the balances will be cleared, except that the Board will not accept the settlement in respect of the Ontario Energy Board Cost Account. As Board staff noted, Hydro One never applied to the Board to establish that account. If Hydro One continues to believe that the balance in that account should be recovered through future rates, then the Board expects Hydro One to provide evidence in this hearing as to why it would be appropriate for the company to recover such costs given that it did not apply to the Board for a deferral account at the time the costs were being incurred.

The Board also accepts the settlement proposal to establish four new variance accounts. Hydro One and the other parties to the settlement should be aware that the Board is providing no assurance that any amounts in those accounts in the future will be included in rates, nor does the approval of the establishment of these accounts indicate any acceptance by the Board of the types of expenditures being recorded in the accounts.

DATED at Toronto, April 18, 2007.

ONTARIO ENERGY BOARD

Signed on Behalf of the Panel

Original signed by

Pamela Nowina
Vice Chair, Presiding Member

APPENDIX 4

HYDRO ONE NETWORK INC.
2007 AND 2008 ELECTRICITY TRANSMISSION RATES

DECISION WITH REASONS

BOARD FILE NO. EB-2006-0501

PARTIAL DECISION AND ORDER
Issued
March 30, 2007

August 16, 2007

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2006-0501

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the transmission of electricity commencing January 1, 2007.

PARTIAL DECISION AND ORDER

Hydro One Networks Inc. ("Hydro One" or the "Company") filed an Application, dated September 12, 2006, with the Ontario Energy Board under section 78 of the *Ontario Energy Board Act 1998, S.O. 1998*, c.15, Schedule B. The Board assigned file number EB-2006-0501 to the Application and issued a Notice of Application dated October 17, 2006.

By letter dated February 14, 2007 and in the February 23, 2007 update to its application, Hydro One requested that a 2007 revenue deficiency deferral account be established beginning January 1, 2007 to record the revenue deficiency between the approved revenue for 2007 and forecast revenues at currently approved transmission rates. Hydro One requested a decision from the Board on this issue by March 31, 2007.

On March 12, 2007 the Board issued Procedural Order #4 requesting that Hydro One make further submissions addressing the following issues:

- The need for the revenue deficiency deferral account;
- Why the issue of the account must be dealt with on an expedited basis;

- What will be booked into the account, and the accounting entries that are proposed to be made;
- The date upon which Hydro One proposes to start booking entries into the account; and
- What, if any, consequences follow if the account is not established at all, or is not established prior to March 31, 2007 as requested.

The procedural order also invited intervenors to respond to Hydro One's submissions and then provided for Hydro One's subsequent reply submissions.

Hydro One Submissions:

Hydro One, in its March 13, 2007 submissions, stated that the EB-2005-0501 transmission earnings sharing mechanism (ESM) was intended to end once new transmission rates were implemented. The establishment of the 2007 revenue deficiency deferral account (RDDA) beginning January 1, 2007, would replace and end the ESM.

Hydro One claimed that the proposed RDDA was more transparent than the ESM, and would be easier to justify and implement for a portion of a year (as un-audited financial results would be used.) In contrast, the part-year RDDA calculations would be based upon approved data consistent with Hydro One Transmission 2007 rate filing. A rates decision in late 2007 would lead to regulatory lag and uncertainty regarding Hydro One in financial markets. An RDDA was also consistent with the Great Lakes Power Limited (GLPL) deferral account (EB-2005-0241) granted in 2005. A decision by March 31, 2007 was requested due to first quarter financial reporting requirements to external investors.

Under the proposed plan, Hydro One submitted that no amounts would be recorded for the ESM in 2007; however, on a monthly basis, the deficiency between the proposed revenue 2007 requirement (per the Hydro One Transmission rate filing) and revenue calculated using current approved rates (by applying a weather normal monthly load forecast consistent with the 2007 load forecast) would be reflected in the deferral account. Monthly carrying costs would be applied to this entry using the short-term interest rate included in the 2007 revenue requirement. Disposition of the account would be subject to future OEB review and approval. Entries would be booked immediately upon receiving a favourable decision from the OEB reflecting the commencement date of January 1, 2007.

Intervenors' Submissions:

Four intervenors responded to the Hydro One submission. The Vulnerable Energy Consumers Coalition (VECC) and Schools Energy Coalition (SEC) argued against granting the account. The Association of Major Power Consumers (AMPCO) and the Power Workers Union (PWU) were supportive of the request.

VECC argued that approval of this account was retroactive ratemaking and should not be approved by the Board. The GLPL case should not be considered as a precedent in this application as the deferral account granted to GLPL was only one aspect of a comprehensive settlement agreement. In addition, the GLPL account only applied to deficiencies starting on April 1, 2005, not January 1. VECC also argued that if the account was granted, no interest should be collected in the account.

SEC argued that the Board does not have the authority to revisit rates. SEC noted that in the EB-2005-0501 ESM decision, the Board stated that it was reluctant to have existing rates declared interim and if the Board had meant the mechanism to last only until January 1, 2007, it would have said so. SEC indicated that it would be unfair to ratepayers to allow Hydro One to revisit rates during a period where it anticipates a revenue deficiency but not do so during a period of over-earning. SEC also mentioned the fact that the GLPL deferral account was part of a comprehensive settlement agreement. SEC also noted that recent decisions of the Board have refused to implement rates retroactively on basis that the applicant had not demonstrated that the delay in arriving at just and reasonable rates by the beginning of the test year was not due to factors within the applicant's control, citing the January 2, 2007 Erie Thames Powerlines Corporation rate order.

AMPCO did not object to the establishment of the RDDA as this action would reassure investors that regulatory risk is minimal. AMPCO stressed that this approval should not pre-empt the Board's hearing process or be misconstrued as prior approval of Hydro One's revenue requirement. AMPCO submitted that any revenue deficiency calculation should be based on actual, non-weather corrected revenue under current rates and that the RDDA should be based only on continuance of program expenditures at the level Hydro One executed in 2006 and not on the increased levels being requested for 2007.

The PWU also supported the approval of the RDDA citing the need for utilities to have sufficient financial certainty so that they can carry out existing and new transmission work programs. The PWU also agreed with Hydro One that the RDDA was consistent with the GLPL decision and stated that the extended application of ESM for 2007 was inappropriate.

Hydro One Reply Submissions:

In its March 21, 2007 reply, Hydro One indicated that it was not requesting prior approval of its proposed 2007 programs or revenue requirements. Hydro One also submitted that SEC's assertions regarding "retroactive rate increases" are not supported as the OEB is not retroactively setting rates and that it is not revisiting rates for a period during which final rates were in place. Hydro One also noted that the settlement agreement in the GLPL case was the basis for the final order issued November 14, 2005, while the deferral account was granted much earlier on March 22, 2005.

Hydro One also stated that it believes that by requiring the use of audited financial statements for the ESM calculations, the Board intended full year application of the ESM, not part year application.

Hydro One submitted that AMPCO's suggestions that the revenue deficiency be calculated on the basis of non-weather corrected actual 2007 revenue and to use 2006 actual program costs is inconsistent with typical regulatory practice and the GLPL decision. Hydro One also pointed out that the GLPL decision included carrying costs in the approved deferral account.

Findings

It often happens that rate proceedings occur within timeframes that do not coincide with the conventional rate period. This can occur for a variety of reasons. In such situations an issue arises as to when the rates approved by the Board will become effective. Determining the effective date for rates is an important aspect of the Board's jurisdiction, and it can have significance for Applicants and ratepayers.

It is clear that such a situation will arise this year with respect to the revenue requirement for Hydro One. It is likely that the final determination of its revenue requirement for 2007 will not be made until the latter half of 2007.

Deferral accounts, such as the one applied for by Hydro One in this proceeding, are accounting devices intended to allow an entity to capture and record in an identifiable location an aspect of operations, the final quantum and disposition of which is dependent on some future unknown event.

In the case of the deferral account applied for by Hydro One, the unknown future event is the Board's final determination of the 2007 revenue requirement, the effective date governing that revenue requirement, and the terms and conditions imposed by the Board on the disposition, if any, of the amounts recorded in the deferral account.

Parties commenting on Hydro One's request for the Revenue Deficiency Deferral Account have raised issues respecting rate retroactivity, and have attempted to define with great particularity the terms and conditions that should govern the creation of the account, if the Board sees fit to approve its creation.

In the Board's view, the time to make these arguments is in the course of the revenue requirement proceeding per se, and, if necessary, at the time Hydro One seeks to have the amounts recorded in the account disposed of, so as to effect its revenue requirement or the resulting rates derived from it. Parties will be free to make whatever submissions they see fit as to the appropriateness of any disposition option.

At this stage, the Board is simply concerned with ensuring that the account meets the objective of administrative and accounting utility.

Accordingly, the Board approves the creation of a deferral account, effective January 1, 2007, to be referred to as the Revenue Difference Deferral Account. This account will record the sufficiency or deficiency arising from the difference between the 2006 Transmission rates, that is, rates that are currently in force, and the rates that would result from the new revenue requirement as determined by the Board in this proceeding. Parties will note that the Board has made the deferral account symmetrical to account for the possibility that the new revenue requirement as found by the Board may be lower than that which underpinned the 2006 rates.

In its materials, the Applicant referenced the Earnings Sharing Mechanism (ESM), which was instituted by a previous Board panel. In the Board's view, the creation of the deferral account as approved by the Board in this proceeding has the effect of terminating the ESM as of December 31, 2006. That is so because the Revenue Difference Deferral Account now accommodates the tracking of sufficiency as well as deficiency and this fact makes the continuation of the ESM unnecessary. If the new revenue requirement is higher than that underpinning the 2006 rates, the account will represent a credit to the utility to the extent of the difference. On the other hand, if the new revenue requirement is lower than that upon which the 2006 rates are based, the entire amount reflected in the account will be to the credit of ratepayers.

The final balance in the account will reflect a series of decisions made by the Board in its determination of the revenue requirement for 2007.

The Board's approval of the creation of this deferral account should not be construed in any degree as predictive of the quantum of, the terms of or the timing of the disposition, if any, of the contents of this account.

THE BOARD THEREFORE ORDERS THAT:

1. Hydro One shall establish a deferral account in which to record the differences in revenue between 2006 Transmission rates currently in force, and the rates that would result from the new revenue requirement as determined by the Board in this proceeding, beginning January 1, 2007. Hydro One is directed to prepare and submit a draft accounting order to the Board reflecting this order.

DATED at Toronto, March 30, 2007.

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

MOODY'S INVESTORS SERVICE

Global Credit Research
Credit Opinion
18 JAN 2012

Credit Opinion: American Transmission Company LLC

American Transmission Company LLC

Wisconsin, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	A1
Commercial Paper	P-1

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Opinion

Corporate Profile

American Transmission Company LLC (ATC: A1 Issuer Rating) is a utility that owns and operates approximately 9,400 miles of electric transmission line in Wisconsin, Upper Michigan and Illinois. ATC is a member of the Midwest Independent System Operator (MISO) and is regulated by the Federal Energy Regulatory Commission (FERC).

SUMMARY RATING RATIONALE

Based on factors in Moody's August 2009 Rating Methodology for Regulated Electric and Gas Utilities (the Methodology), ATC's A1 Issuer Rating reflects the low risk nature of its regulated operations and a federal regulatory framework that provides timely recovery of operating expenses and a return of and on invested capital. ATC's Issuer Rating is two notches above the indicated rating according to the Methodology.

DETAILED RATING CONSIDERATIONS

Federal regulatory environment provides for steady, predictable cash flow with limited regulatory lag

As an independent transmission company, ATC's rates are regulated by the FERC. ATC's transmission service revenue is determined through a forward-looking FERC approved formula designed to reimburse the company for all reasonable operations and maintenance expenses, income and franchise taxes, depreciation and amortization and to provide a return on assets employed in the provision of transmission services, including construction work in progress. The formula contains an automatic annual true-up for all operating and capital costs. These features are intended to ensure that the company recovers its allowed costs and returns within a two year period. In addition, to encourage greater investment in transmission infrastructure, the FERC allows independent transmission systems owners to earn incentive rates of return that tend to be above those allowed for state-regulated utilities. The FERC allows ATC to collect in its rates a 12.2% ROE on a 50% equity ratio.

Because the rate setting process is not a contested process before state commissions and since it works to ensure timely recovery, we generally consider revenues collected under this regulatory framework to be more stable and predictable than state-regulated utility businesses. However, the rate setting mechanism is still subject to challenge by interested parties including state regulators via a proceeding at the FERC. The current rate making treatment remains in effect until December 31, 2012. After this date, the company may elect to change or interveners may request a change in the revenue requirement formula. Ongoing favorable regulatory support represents an essential factor in ATC's ability to maintain its financial strength. Accordingly, within the framework of the Methodology, ATC maps to a rating factor in the Aa range for Factor 1: Regulatory Framework and the A range for Factor 2: Ability to Recover Costs and Earn Returns.

Credit metrics weak for rating

ATC's credit metrics have tended to map to the low-A levels or high-Baa levels based on ranges in the Methodology. This includes cash flow cah from operation pre-working capital) to debt of 20% and cash flow interest coverage of about 4.8-5.0x. Debt to capitalization is expected to remain at around 55%, which maps to a borderline Baa/Ba. Credit metrics are expected to remain at around those levels going forward as long as the current FERC rate-setting mechanisms remain in place.

Customer concentration risk somewhat mitigated by MISO

Approximately 90% of ATC's revenues are generated by providing transmission services to Wisconsin electric utilities. Although this reflects ATC's customer concentration risk, its status as a member of MISO acts to limit the risk of non-payment. Specifically, ATC invoices and directly collects from customers the amounts due for providing transmission services (the remaining revenue is generally collected by MISO). MISO employs strict credit policies for payment of transmission services that it provides on behalf of its members and sets credit limits based on credit quality. If there is an event of default by a transmission customer, MISO may begin proceedings with FERC to cancel transmission services and draw on the credit support; losses are generally socialized.

Joint venture with Duke Energy allows growth but carries increased credit risks

In April 2011, ATC formed a 50/50 joint venture with Duke Energy (Duke: Baa2 stable) named DATC to build, own and operate transmission assets. The venture has so far made minimal investments. In December 2011, DATC acquired the Zephyr Power Transmission Project, a proposed 950-mile transmission line that would deliver wind energy from Wyoming to California and the southwestern U.S. The total cost of the project is projected to be about $3.5 billion and could be online by 2020. So far, the project is still in the permitting stage and significant capital expenditures are not expected to be made until around 2017. Nevertheless, the structure and funding of the Zephyr project and other DATC projects could significantly impact ATC's current A1 Issuer Rating.

Liquidity

ATC has an adequate liquidity profile with reasonably predictable cash flow generation but we expect ATC to have on-going funding needs for its planned capital expenditures. In 2010, cash from operations was around $330 million and we expect cash flow to grow moderately over time with continued rate base growth. Over the next few years, we expect ATC to have capital expenditures of approximately $250-350 million. ATC seeks to maintain an 80% dividend payout ratio and generates equity capital through a combination of retained earnings and voluntary mandatory equity contributions from its members. Shortfalls in funding its capital expenditures and dividends are expected to be met by a combination of equity contributions from its owners and privately placed debt issuance that maintain its existing capital structure.

ATC funds its short-term cash requirements, including construction costs, with a $300 million commercial paper program. As the company's commercial paper borrowing capacity is utilized, it refinances outstanding commercial paper through long-term private debt offerings. The CP program is backstopped by a $300 million credit facility expiring January 2014. The sole financial covenant is a maximum consolidated leverage test under which ATC is in compliance. As of September 30, 2011, ATC had $156 million of commercial paper outstanding and no cash on hand.

Rating Outlook

The stable rating outlook for ATC reflects our expectation that ATC will continue to benefit from the favorable FERC-regulatory framework and that the utility will maintain its existing debt to capitalization ratio of 50-55% and cash flow to debt of approximately 20%.

What Could Change the Rating - Up

Given that the current rating is above the indicated rating in the Methodology based grid and is among the highest rated U.S. utilities, an upgrade is unlikely. Longer-term, core financial metrics would need to improve considerably, such as cash flow to debt exceeding 30% with debt-to-capitalization under 40% on a sustained basis.

What Could Change the Rating - Down

ATC's Issuer Rating could be downgraded if there are successful challenges to ATC's tariff setting mechanism, if coverage metrics decline moderately including cash flow to debt falling below 18% on a sustained basis or if the company pursues expansion strategies directly or through its JV with Duke Energy that would materially increase overall business risk.

Rating Factors

American Transmission Company LLC

Regulated Electric and Gas Utilities Industry [1][2]	**FYE 2010**		**Moody's 12-18 Month Forward View As of January 17, 2012**	
Factor 1: Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Regulatory Framework		Aa		Aa

Factor 2: Ability To Recover Costs And Earn Returns (25%)				
a) Ability To Recover Costs And Earn Returns		A		A
Factor 3: Diversification (10%)				
a) Market Position (10%)		A		A
Factor 4: Financial Strength, Liquidity And Key Financial Metrics (40%)				
a) Liquidity (10%)		Baa		Baa
b) CFO pre-WC + Interest/ Interest (3 Year Avg) (7.5%)	4.8x	A	4.8x-5.1x	A
c) CFO pre-WC / Debt (3 Year Avg) (7.5%)	20%	Baa	19-21%	Baa
d) CFO pre-WC - Dividends / Debt (3 Year Avg) (7.5%)	9%	Baa	9-10%	Baa
e) Debt/Capitalization (3 Year Avg) (7.5%)	56%	Ba	54-56%	Ba
Rating:				
a) Indicated Rating from Grid		A3		A3
b) Actual Rating Assigned		A1		A1

* THIS REPRESENTS MOODY'S FORWARD VIEW; NOT THE VIEW OF THE ISSUER; AND UNLESS NOTED IN THE TEXT DOES NOT INCORPORATE SIGNIFICANT ACQUISITIONS OR DIVESTITURES

[1] All ratios are calculated using Moody's Standard Adjustments. [2] As of 12/31/2010; Source: Moody's Financial Metrics

STANDARD & POOR'S

Global Credit Portal®
RatingsDirect®

May 24, 2012

Summary:
American Transmission Co.

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Table Of Contents

Summary:

American Transmission Co.

Credit Rating: A+/Stable/A-1

Rationale

The ratings on Wisconsin-based electric transmission company American Transmission Co. (ATC) reflect Standard & Poor's Ratings Services' assessment of the company's business risk profile as "excellent," which we base on very low operating risk and a formula regulatory rate-setting structure that the Federal Energy Regulatory Commission (FERC) governs.

We view ATC's financial risk profile as "intermediate" based on sustainable and highly predictable credit measures. ATC, a privately held company, owns and operates 9,400 miles of transmission lines, mainly in Wisconsin and Michigan, and to a much lesser extent, in Minnesota and Illinois.

The excellent business profile reflects FERC's highly supportive regulatory rate construct. FERC is the sole rate regulator for ATC. Also, as a pure electric transmission owner, ATC is exposed to considerably less operational risk than is a vertically integrated utility. Further supporting our excellent business risk assessment is the transfer of operational control of ATC's facilities to the Midwest Independent Transmission System Operator Inc. (MISO). This shifts responsibility away from ATC for such oversight matters as the monitoring and directing the operations for congestion and outages. FERC's supportive rate treatment enhances the timeliness of expense and capital spending recovery and limits the year-to-year variability of the company's cash flow. Specifically, FERC allows a cash return on construction work in progress, sets rates prospectively with annual true-ups, and provides a healthy authorized after-tax return on equity of 12.2% on a hypothetical capital structure of 50% (actual equity is typically closer to 45% to 46%).

The intermediate financial risk profile reflects ATC's steady and consistent cash flow and leverage measures, and our expectations that this history of very little variance will continue. Our expectations for 2012 and 2013 are for funds from operations (FFO) to total debt to be about 19.2% and 19.3%, and adjusted debt to EBITDA to be about 4.1x and 4.2x, These measures are in line with, and typically closely mimic, past performance. For example, in 2011, adjusted FFO to total debt was 19.6% and adjusted debt to EBITDA was 4.1x. We note that the exceptional transparency of ATC's cash flow generation performance and the consistent capital structure enable Standard & Poor's to relax the published ratio guidelines that are otherwise typical for the 'A+' corporate credit rating.

Absent significant growth outside of its service territory, we expect that ATC's annual capital spending will average about $270 million over each of the next three years, which is considerably lower than its recent historical annual average of about $400 million.

We expect ATC to have negative discretionary cash flow over the near and intermediate terms primarily because of annual earnings distributions to its owners, which are about 80% of earnings before taxes. This is not a credit concern because we expect that ATC will continue to fund capital projects, irrespective of their location or ownership structure, in a manner that supports its credit quality, including requests of its equity owners to contribute capital to maintain capital structure balance.

In April 2011, ATC formed a joint venture with Duke Energy Corp. (A-/Stable/A-2) called Duke-American Transmission Co. LLC (DATC), in which equity ownership is split evenly between the two companies. The intent of the joint venture, which could be key to ATC's future growth strategy, is to identify, build, own, and operate new transmission projects outside of ATC's current service area. While we anticipate that the joint venture's growth, structure, and financing will be consistent with the company's existing financial policies, the scale of some of the potential projects is substantial. As such, this venture may evolve into a critical rating factor.

Liquidity

Our short-term rating on ATC is 'A-1'. We consider liquidity as "adequate" under our corporate liquidity criteria, which categorizes liquidity under five standard descriptors. The company recently enhanced its sources of liquidity by repaying all outstanding commercial paper in early 2012, thereby freeing up capacity under the company's $300 million revolving credit facility. Stable, regulated, asset-intensive utility operations anchor the company's business and provide reliable cash flow and access to capital markets under virtually all market conditions.

Projected sources of liquidity, mainly operating cash flow and bank line availability, exceed projected uses, mainly necessary capital spending, and earnings distributions, by more than 1.2x. ATC's credit agreement terminates in January 2014 and includes a financial covenant requiring a consolidated ratio of total debt to total capital of no more than 65%. As of March 31, 2012, the leverage ratio was comfortably in compliance.

Outlook

The stable outlook on the rating reflects ATC's straightforward and proven business model, a highly constructive regulatory scheme, and very predictable cash flow from a reliable transmission network. The stable outlook also reflects Standard & Poor's baseline forecast that adjusted FFO to debt will approximate 19% and adjusted debt to total capital 55% to 56% over the intermediate term. A rating upgrade would depend on greater clarification of ATC's evolving growth strategy with DATC and a strengthening of financial measures, including a sustained FFO/debt in the low to mid-20% range. A ratings downgrade is highly unlikely, but could occur if an unexpected and dramatic weakening of the regulatory cost recovery construct caused adjusted FFO to debt to fall below about 18% and adjusted debt to total capital to rise toward about 58% on a sustained basis.

Related Criteria And Research

- Liquidity Descriptors For Global Corporate Issuers, Sept. 28, 2011
- Business Risk/Financial Risk Matrix Expanded, May 27, 2009
- Analytical Methodology, April 15, 2008

STANDARD & POOR'S RATINGSDIRECT

RESEARCH

Peer Comparison: North American Stand-Alone Transmission Companies Deliver Electricity...And Profits

Publication date: 26-Apr-2006
Primary Credit Analyst: Terry A Pratt, New York (1) 212-438-2080; terry_pratt@standardandpoors.com

Much investment in U.S. and Canadian electric transmission is under way, and fairly new, stand-alone transmission-only companies sponsor a decent share of it. Some of these companies were created when large, vertically integrated utilities sold their transmission assets to meet regulatory requirements or respond to favorable financial incentives. The stand-alone transmission company, or transco, is proving to be a good business model for making transmission investments and providing shareholder returns--a favorable combination that could support a virtuous cycle for additional investment in this critical infrastructure.

Standard & Poor's Ratings Services has solid investment-grade ratings on three North American transcos:

- American Transmission Co. (ATC; A+/Stable/-- corporate credit rating and senior unsecured rating),
- Independent Transmission Co. (ITC), a subsidiary of ITC Holdings Corp. (BBB/Stable/-- corporate credit rating; 'BBB+' senior secured rating), and
- AltaLink L.P. (A-/Stable/-- corporate credit rating and senior secured rating).

Despite each having investment-grade creditworthiness, the companies are exposed to notably different business and financial risks, which are compared in depth below.

Background

Wisconsin's electric industry restructuring legislation of 1997 and 1999 supported the creation of ATC when the state's utilities divested their transmission assets. ATC began operation in 2001 and provides high-voltage transmission service to utilities and electric cooperatives using about 8,900 miles of line. ATC is responsible for monitoring the flow of electricity across the transmission system, and performing operations and maintenance, planning, and construction. ATC is owned by numerous parties that contributed transmission assets or cash in exchange for equity stakes. ATC's main owners include Wisconsin Energy Corp. (BBB+/Negative/A-2) with 32%, WPS Resources Corp. (A/Negative/A-1) with 26%, and Alliant Energy Corp. (BBB+/Stable/A-2) with 23%. Northern States Power Wisconsin (BBB+/Stable/--) did not contribute assets and is not an owner.

ITC was created as a business unit of Detroit Edison Co. (BBB/Stable/A-2) in 1999, and started operating as a wholly owned subsidiary of DTE Energy Co. (BBB/Stable/A-2) in 2001. Kohlberg Kravis Roberts & Co. (KKR) and Trimaran Capital Partners LLC purchased ITC from DTE Energy in 2002 for $610 million and made it a stand-alone transmission company in February 2003. ITC initially relied on DTE Energy for most services, but became truly independent in 2004. ITC provides transmission service primarily to Detroit Edison's southeastern Michigan markets, with about 2,700 miles of line. ITC's parent, ITC Holdings, performed a successful IPO in 2005.

In April 2002, AltaLink purchased the regulated transmission assets of TransAlta Corp. (BBB/Stable/--) in the Province of Alberta (AAA/Stable/A-1+) for C$830 million and became the first investor-owned independent transmission provider in Canada. AltaLink is wholly owned by AltaLink Investments L.P. (BBB-/Stable/--). The ultimate unitholders of AltaLink Investments are SNC-Lavalin Group Inc.

(BBB+/Stable/--) (50%), the Ontario Teachers' Pension Plan Board (25%), Macquarie Essential Assets Partnership (MEAP) (15%), and developer Trans-Elect Inc. (10%). However, a proposed ownership change to 77% SNC-Lavalin and 23% MEAP is awaiting regulatory approval. AltaLink owns and operates about 7,200 miles of line.

Rating Methodology

ITC and AltaLink have a holding company structure, but ATC does not. For this peer comparison, we are comparing ATC, the consolidated entity of ITC and ITC Holdings, and the nonconsolidated entity AltaLink. The 'BBB' corporate credit rating on ITC and its parent ITC Holdings reflect the consolidated credit profile of the two companies. We rate ITC's senior secured debt one notch above the consolidated corporate credit rating because of the collateral strength; we rate ITC Holdings senior unsecured debt one notch below the corporate credit rating due to structural subordination from ITC. However, for AltaLink, legal and structural ring-fencing measures permit us to insulate its rating somewhat from its parent, and so for this analysis, only the business risk profile and financial risk profile of AltaLink is of primary relevance.

Business Risk Profile

Standard & Poor's assigns corporate utilities a business risk profile score ranging from '1' (excellent) to '10' (vulnerable), based mainly on their regulation, markets, operations, competitiveness, and management. Competitiveness is not a major risk factor for these three transcos. We assign scores of '1' to ATC and '2' to AltaLink and ITC, but we note that AltaLink has a lower business risk profile than ITC due to more favorable regulation and markets.

Regulation

The FERC regulates the rates of ATC and ITC, while the state public service commissions of their service territories regulate their transmission siting. The 2005 Energy Policy Act gave the federal government a wider role in transmission siting, and federal-local turf battles could complicate local regulatory relations for ATC and ITC. Because the Alberta Energy and Utilities Board (Alberta EUB) determines AltaLink's annual revenue requirement and oversees siting activities within the province, AltaLink is not exposed to provincial and national regulatory turf scuffles.

Each company has low regulatory risk, but ATC's risk is lowest among the three. ATC currently operates under a FERC-approved settlement that includes a 12.2% ROE based on a hypothetical capital structure of 50% equity. Other favorable provisions include the ability to earn a return on construction-work-in-progress (CWIP) for projects beginning in 2005, rate setting based on prospective data, and an annual end-of-year true up. The CWIP treatment is an important feature that reduces upfront financing risk and liquidity concerns, given the company's large planned capital expenditure program. Also, ATC charges a fixed monthly fee during a given year, which reduces exposure to cash flow variability that could result from changes in demand caused by weather. ATC's allowed ROE could have been higher--among other things, the FERC reduced it by 18 basis points in exchange for the favorable CWIP treatment to reflect lower risk, and by another 100 basis points because ATC's operations and management are not considered independent from market participants under FERC requirements.

Like its peers, AltaLink operates under traditional cost-of-service and rate-of-return regulation. Favorably, cash flow stability is gained through a fixed cost-of-service revenue cap mechanism, which eliminates cash flow variability during the year that might otherwise occur due to variability of electricity demand from weather or economic events. In this structure, AltaLink receives 12 equal monthly payments during a year. Additionally, the company's revenue cap is based on prospective data. However, AltaLink earns a comparatively low ROE compared with its U.S. counterparts, and like ITC, does not earn a return on CWIP. AltaLink's approved revenue requirement includes an allowed ROE, set through the Alberta EUB's generic annual adjustment mechanism that is valid within a range of possible outcomes of 7.6% to 11.6%, and is based on a 35% equity base. The annual adjustment is directly linked to long-term Treasury bonds, and therefore, the allowed ROE has decreased in recent years due to the current low interest rate environment--AltaLink's allowed ROE is 8.93% in 2006 versus 9.5% in 2005 and 9.6% in 2004. Such low ROEs and thin equity layers are common to Canadian regulated utilities. The Alberta EUB is not likely to review its generic cost of capital until 2009 unless the adjustment falls outside the band.

ITC is also subject to rate-of-return regulation, but is authorized by the FERC to earn a solid 13.88% ROE with a capital structure that has a 60% equity component. ITC earns 100 basis points of the total ROE by being structured with management and operations completely independent from market participants. ITC began operations under a rate freeze, which concluded at year-end 2004 and which required the company to defer recovery of capital expenditures and related costs. The company began recovering these costs in 2005 with rate increases. The company does not earn a return on CWIP. ITC does benefit from an annual true-up in mid-year, although it is based on data from the most recent rather than the prospective calendar year. Another challenge for ITC is that the current rate paradigm is good through early 2008 and how the FERC will set rates thereafter is unknown.

Markets

Market-risk assessment for transcos focuses primarily on demand uncertainty and counterparty issues. Market risk is a distinguishing characteristic of the three companies, and a critical issue for ITC's credit rating.

ATC provides service to a number of utilities that collectively serve about five million customers in the eastern two-thirds of Wisconsin, including the population centers, the Upper Peninsula of Michigan, and a small enclave in northern Illinois along the Wisconsin border. In these markets, the load growth is favorable at about 2.5% per year. However, ATC is exposed to revenue concentration because about 86% of revenues come from three utility companies, Wisconsin Energy (47%), Alliant Energy (19%), and WPS Resources (20%). Because ATC has limited capacity to remedy a decline in a customer's credit quality, it is exposed to counterparty credit risk, but somewhat offsetting this risk is that the Wisconsin utilities have lower-than-average business risk profiles and are rated in the 'A' category. In addition, ATC enjoys some customer diversity.

In contrast, ITC is very limited in geographic scope. It primarily serves the Detroit Edison service territory of southeastern Michigan, which has about 2.2 million customers. Detroit Edison provides ITC with about 77% of its revenues, which exposes ITC to very high customer concentration risk. For this reason, we limit the ITC rating to that of Detroit Edison. We would not expect ITC to stop serving Detroit Edison if the utility were to stop paying for transmission service due to some adverse business event. Cash flow to ITC would likely resume at some point, but ITC may not have sufficient liquidity to meet its obligations during a protracted period of nonpayment. Moreover, the demand prospects for much of ITC's service territory are uncertain, given current economic conditions for area industrial buyers, mainly the struggling regional automobile industry.

AltaLink owns about 40% of the transmission rate base in Alberta located in the more populated southern half of the province. Forecast growth in Alberta for electricity consumption averages between 2% and 3% per year and is among the highest in Canada, and this growth contributes to AltaLink's growing asset base, which the company expects will almost double in the next five years. In contrast to ATC and ITC, AltaLink's counterparty credit risk is very low; the Alberta Electric System Operator (AESO), an agent of the province, pays AltaLink for all transmission services and bears the counterparty risk exposure associated with the transmission system end-users. The AESO is independent of any industry affiliations and owns no transmission assets.

Operations

Routine operations and maintenance (O&M) risk of the three companies has not emerged as a credit differentiator, but construction performance does present uncertainties and thus remains a factor in the ratings. The utility owners of ATC perform nearly all of its O&M, administrative, and construction activities. Aside from construction risk, we view ATC's business risk as low in this area. Over the next 10 years, ATC expects to invest about $3.4 billion to improve transmission reliability and capacity, both intrastate and interstate. This plan includes a Wausau, Wis. to Duluth, Minn. transmission line costing about $420 million that may be built by mid-2008. ATC, Wisconsin Public Service Corp. (A+/Negative/A-1), and ALLETE Inc. (BBB+/Stable/A-2) will jointly fund the construction. Although ATC has the experience to build this line and benefits from CWIP treatment in rates, there are always construction risks associated with large infrastructure projects that could negatively affect cash flow and liquidity balances.

ITC conducts its own routine O&M and administration services. It had until recently relied contractually on Detroit Edison to provide these services. The company contracts out major construction activities. Again, the overall O&M risk is low, but construction risk is ever present. ITC's current plan forecasts capital investments of nearly $1 billion over the next seven years.

ATC and ITC are members of the Midwest Independent Transmission System Operator Inc. (MISO; A+/Stable/--), which performs a number of key operational and planning functions for the transmission grid. While ATC and ITC retain responsibility for O&M, MISO is responsible for tariff administration, scheduling, and planning, as well as managing the energy and financial transmission rights markets. MISO serves as the billing coordinator, but MISO is not the credit counterparty for ATC or ITC. The situation for ATC and ITC is more risky than for AltaLink, whose sole credit counterparty is the provincial independent grid operator, AESO.

AltaLink is a transmission facilities operator (TFO). The AESO contracts with TFOs to acquire transmission services and provide customer transmission access, and holds responsibility for identifying the need for new transmission facilities in Alberta. The Alberta EUB must approve investment. AltaLink performs its own O&M and administrative functions. The company operates its assets well, with good reliability performance in line with its Canadian peers. About 60% of AltaLink's assets are less than 20 years old, and the favorable age profile will improve with new additions. The company contracts out for major construction services, mostly with its main sponsor, SNC-Lavalin, a Canada-based, global construction firm experienced with utility operations. AltaLink expects capital spending of about C$200 million per year to 2009, or about double the historical annual investment, to address transmission congestion and high demand growth.

Management

Standard & Poor's continues to gain confidence in the management capability of stand-alone transcos, given their generally favorable track record thus far in sustaining and improving operations and maintaining good regulatory relations. ATC management comes from its utility owners, which are well experienced in transmission operations and regulatory matters. Similarly, ITC management consists of experienced Detroit Edison personnel. However, we believe that ITC's management may be influenced by its key owners KKR and Trimaran, which, by their nature, may not have a long-term investment horizon in mind. AltaLink is managed by experienced personnel, and supported by the substantial utility construction experience of its main owner, SNC-Lavalin. In contrast to ITC's ultimate ownership, SNC-Lavalin may have a longer-term investment horizon.

Financial Risk Profile

Standard & Poor's determines the transcos' financial risk profiles mainly by examining their corporate governance in terms of risk tolerance and financial policies, and their cash flow adequacy, capital structure, and liquidity. Aside from differences on leverage aggressiveness, the companies are generally similar on corporate governance, so the following discussion addresses cash flow and capital structure, where material differences emerge.

Cash flow adequacy

Each company benefits from generally stable cash flow derived entirely from regulated transmission operations. The table provides a comparison of key financial metrics. ATC's financial performance along with its lower business risk score support a higher rating than those of its peers. ITC and AltaLink have similar financial metrics, following an improvement in ITC performance in 2005, with a rise in rates following the end of a price cap. We expect that ATC and ITC to maintain their current performance level in the next two to three years, and we expect AltaLink's 2006 ratios to be in line with those of 2005. We also expect AltaLink's ratios to weaken for 2007 through 2009, but then return to 2005 levels once the build-out period ends.

Table 1

Transco Financial Performance Summary

	ATC		ITC		AtlaLink	
	2005	**2004**	**2005**	**2004**	**2005**	**2004***
FFO to interest coverage (x)	4.4	4.8	3.9	2.5	3.8	3.3
FFO to total debt (%)	23	25	17	9	16	10
Total debt to total capitalization (%)	52	49	66	71	63	61

*Eight months ended Dec. 31, 2004.

ITC's corporate credit rating is two notches below that of AltaLink, and ITC's senior secured debt rating is only one notch below that of AltaLink's. AltaLink's senior secured debt does not benefit from sufficient collateral to warrant being notched up from the company's corporate credit rating. A key reason for this rating differential is ITC's reliance on Detroit Edison for about three-quarters of its cash flow. Another reason is that ITC's market is less favorable for demand growth than southern Alberta's. Furthermore, ITC employs historical costs in rate-setting rather than forward costs as AltaLink does.

Capital structure/asset protection

ATC employs a more conservative financial structure than ITC or AltaLink. ATC's 50% leverage is more than 10% lower than its peers. Again, ITC's leverage is based on leverage at both ITC and its parent--but it is clearly aggressive. Although AltaLink's leverage is also aggressive when compared with ATC and ITC, its level is in line with the typical 60% leverage for Canadian utilities.

ATC's debt amortization schedule is also more favorable than its peers. Most ITC and ITC Holdings debt matures in 2013, resulting in high refinancing risk. AltaLink's schedule is somewhat better, with C$100 million due in 2008 and another C$325 million due in 2013, and should improve as the company grows and undertakes new debt issuance. ATC's debt maturities, however, are comparatively well spread out, with $300 million due in 2011, $100 million in 2015, and the remainder in later years.

As a result, ATC has greater financial flexibility than ITC or AltaLink, and financial flexibility is important given the very large capital improvements programs that they all envision. ATC lacks direct access to public equity markets, but periodically makes capital calls on its owners who then have the option to make incremental equity investments. ITC Holdings has shown its ability to tap into equity markets through a successful IPO in 2005. While only a small portion of IPO proceeds made it down to ITC, the success demonstrates a level of investor interest in this asset class even at high leverage levels. Because AltaLink has no access to equity markets, however, ongoing equity contributions from the ultimate shareholders during the robust capital program through to 2009 will be required to sustain the rating.

CANADA

National Energy Board

Reasons for Decision

Sable Offshore Energy Project

and

Maritime & Northeast Pipeline Project

GH-6-96

December 1997

Facilities

National Energy Board

Reasons for Decision

In the Matter of

The Sable Offshore Energy Project

Application dated 11 June 1996, as amended, for Facilities and Tolls

and

The Maritime & Northeast Pipeline Project

Application dated 7 October 1996, as amended, for Facilities & Tolls

GH-6-96

December 1997

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IN THE MATTER OF the *National Energy Board Act* (*NEB Act*), and the Regulations made thereunder; and

IN THE MATTER OF an application dated 30 May 1996 by Mobil Oil Canada Properties and Shell Canada Limited., on behalf of the Sable Offshore Energy Project, for a Certificate under section 52 of the *NEB Act* and an Order under Part IV of the *NEB Act* to construct and operate facilities and to conduct activities that fall under the jurisdiction of the National Energy Board; and

IN THE MATTER OF an application dated 7 October 1996 by Maritimes & Northeast Pipeline Management Ltd., on behalf of Maritimes & Northeast Pipeline Limited Partnership, for a Certificate under section 52 of the *NEB Act* and an Order under Part IV of the *NEB Act* to construct and operate facilities and to conduct activities that fall under the jurisdiction of the National Energy Board; and

IN THE MATTER OF Hearing Order GH-6-96;

HEARD in Moncton, New Brunswick, April 4, 1997, in Antigonish, Nova Scotia, April 5, 1997, in Halifax, Nova Scotia on 7 to 11, 14 to 18, 21 to 24 April 1997, in Fredericton, New Brunswick on 28 to 30 April 1997, 1 and 2, 5 to 9, 12 to 16 May 1997, and in Halifax, Nova Scotia on 26 to 30 May 1997, 2 to 6, 9 to 13, and 23 June 1997, 2 to 4, 7 to 11 and 14 July 1997.

BEFORE:

K.W. Vollman	Presiding Member
R.O. Fournier	Member
A. Côté-Verhaaf	Member

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R. Starr	Nova Scotia New Democratic Party
G. Archibald	Progressive Conservative Caucus of Nova Scotia
D. Ablonczy	Reform Party of Canada
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R.J. Harrison	Central Maine Power Company
N. Miller	Corridor Resources Inc.
H. Hancock	Country Harbour Sea Farms Co-Operative Limited
J.H. Smellie S. Kirstiuk J.F. Bowe, Jr.	Irving Oil Limited
F.V.W. Penick	Kimberly-Clark Nova Scotia, a Division of Kimberly-Clark Incorporated, et al (Large Industrial Group)
K.D. Dyte L.E. Smith R.G. Grant	Mobil Oil Canada Properties
L.L. Manning	Mosbacher Operating Ltd.
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C.K. Yates P.W. Gurnham R.S. Niedermayer	Nova Scotia Power Incorporated

F.V.W. Penick	PanCanadian Petroleum Limited
C.B. Woods	PanEnergy Marketing Limited Partnership
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R. Rankin B. MacDonald	Halifax Regional Municipality

H. MacLeod	Municipality of the District of Guysborough
D. Hawkins	Government of Newfoundland and Labrador
G.L. MacDonald A.J. England	Guysborough County Regional Development Authority
R. Redgrave	Maine Public Utilities Commission
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D.G. Davies H.R. Huber T.M. Hughes G. Corsano	Province of Nova Scotia
M. Ledwell V. Bulger L. Walsh	Province of Prince Edward Island
C. MacKinnon	City of Saint John
P. Doig	Strait-Highlands Regional Development Agency, Town of Port Hawkesbury, and Strait Area Chamber of Commerce
F. Leblanc, M.P.	On his own behalf
E. Lockerby	On his own behalf
G. Randall	On his own behalf
P. Noonan C. Beauchemin	Board Counsel

Foreword

The Proponents of the Sable Offshore Energy Project (SOEP) and of the Maritimes and Northeast Pipeline Project (M&NPP) submitted applications to the following regulatory agencies: the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB); the National Energy Board (NEB or the Board); and the Nova Scotia Energy and Mineral Resource Conservation Board (NSEMRCB).

Given that each jurisdiction required a public review of both projects, an opportunity emerged to conduct a joint public review as a means of streamlining the regulatory process. The outcome was the Agreement for a Joint Public Review of the Proposed Sable Gas Projects (the Agreement) forged among the Ministers of Environment for Canada and Nova Scotia, the Ministers of Natural Resources for Canada and Nova Scotia, the Chairman of the National Energy Board and the Acting Chief Executive Officer of the Canada-Nova Scotia Offshore Petroleum Board (the Signatories). The purpose of the Agreement was to co-ordinate the environmental and socio-economic assessment requirements of the Signatories by providing a review of the environmental and socio-economic effects likely to result from the Projects.

A Joint Public Review Panel was struck by the Signatories comprising five members. The Chairman was appointed as a temporary member of the NEB, and two of the remaining members were full-time NEB Members.

The Terms of Reference contained in the Agreement stipulated that the review procedures set by the Joint Review Panel would include the *NEB Rules of Practice and Procedure* which contemplate testimony under oath or solemn affirmation, cross-examination and argument. The applications received from SOEP and M&NPP were simultaneously considered by the NEB during the Joint Public Review proceeding. The three NEB Members on the five member Joint Review Panel acted as the NEB panel for both the SOEP and the M&NPP facilities under Hearing Order GH-6-96.

The Joint Review Panel released its report on the environmental and socio-economic effects of the Projects on 27 October 1997. The Summary and Conclusions section from that report is included in this document as Chapter 2.

The Board has considered the Joint Public Review Panel Report Recommendations and the Government of Canada's response thereto, and is of the view that, taking into account the implementation of appropriate mitigation measures identified in the course of the Joint Panel Review proceedings, the Projects are not likely to cause significant adverse environmental effects. The Board accepts all the pertinent recommendations of the Joint Public Review Panel and, where appropriate, the recommendations have been incorporated as certificate conditions. The following chapters constitute the Board's decisions on those matters under its jurisdiction and the reader should refer to the Joint Review Panel Report for the reasons therefore.

Chapter 1

Introduction

The Sable Offshore Energy Project (SOEP), a consortium consisting of Mobil Oil Canada Properties Limited, Shell Canada Limited, Imperial Oil Resources Limited, and Nova Scotia Resources Limited, plans to develop six fields located on the Scotian Shelf: Venture; South Venture; Thebaud; North Triumph; Glenelg; and Alma. SOEP proposes the construction of offshore and onshore facilities for the drilling, production, transmission and processing of natural gas. Gas and associated natural gas liquids will be collected from offshore production platforms and brought ashore by means of a submarine pipeline to a gas plant to be located at Goldboro, in Guysborough County, Nova Scotia. Natural gas liquids will be transported from the gas plant by an onshore pipeline to Point Tupper, Nova Scotia for further handling and shipping.

Gas production is projected for late 1999, starting at Thebaud, Venture and North Triumph. Additional fields will be developed as required to maintain the sales gas rate of 13.0 million cubic metres per day (460 million cubic feet per day). Development of the South Venture, Glenelg and Alma fields is currently planned for 2004-2007. Project facilities will be designed so that, with proper inspection, maintenance and repairs, they can be used well beyond the current proposed project life of 25 years. This design approach will enable later development of additional satellite fields. Further exploratory discoveries will be incorporated into SOEP as warranted. Accordingly, SOEP is viewed as a seed project which should promote future development of offshore gas reserves on the Scotian Shelf.

The Maritimes and Northeast Pipeline Project (M&NPP) proposal will transport the processed natural gas via an onshore pipeline to Canadian and U.S. markets. The facilities will consist of 558 kilometres of 762 millimetre pipeline extending from the outlet point of the Goldboro gas plant, first in a northwesterly direction passing near New Glasgow and Tatamagouche, Nova Scotia, crossing the Nova Scotia-New Brunswick border near Tidnish. Approximately 234 kilometres of pipeline will be located in Nova Scotia. The pipeline will traverse New Brunswick in a westerly direction passing near Moncton and Chipman. From Chipman it will proceed in a southwesterly direction passing near Fredericton, crossing the Saint John River and proceeding to the international border near St. Stephen, New Brunswick. Approximately 324 kilometres of pipeline will be located in New Brunswick. At the border, the pipeline will connect with U.S. facilities that will deliver the gas to the northeastern states and ultimately tie into the existing North American natural gas pipeline grid.

The NEB formally referred the SOEP proposal to the federal Minister of the Environment in June 1996 for environmental assessment by a panel and the M&NPP proposal was added in October 1996.

The Agreement for a Joint Public Review of the Proposed Sable Gas Projects set out the process for conducting the Joint Public Review. It provided that the public review would allow for the collection and examination of environmental evidence and the hearing of argument on the environmental effects of the Projects for use in subsequent deliberations and decision making on the applications by regulatory authorities. It also provided a forum for one of the members acting as Commissioner to the CNSOPB to publicly distribute the Development Application as well as permit the collection of information in relation to the Development Plan Application for use in subsequent deliberations and recommendations to the CNSOPB.

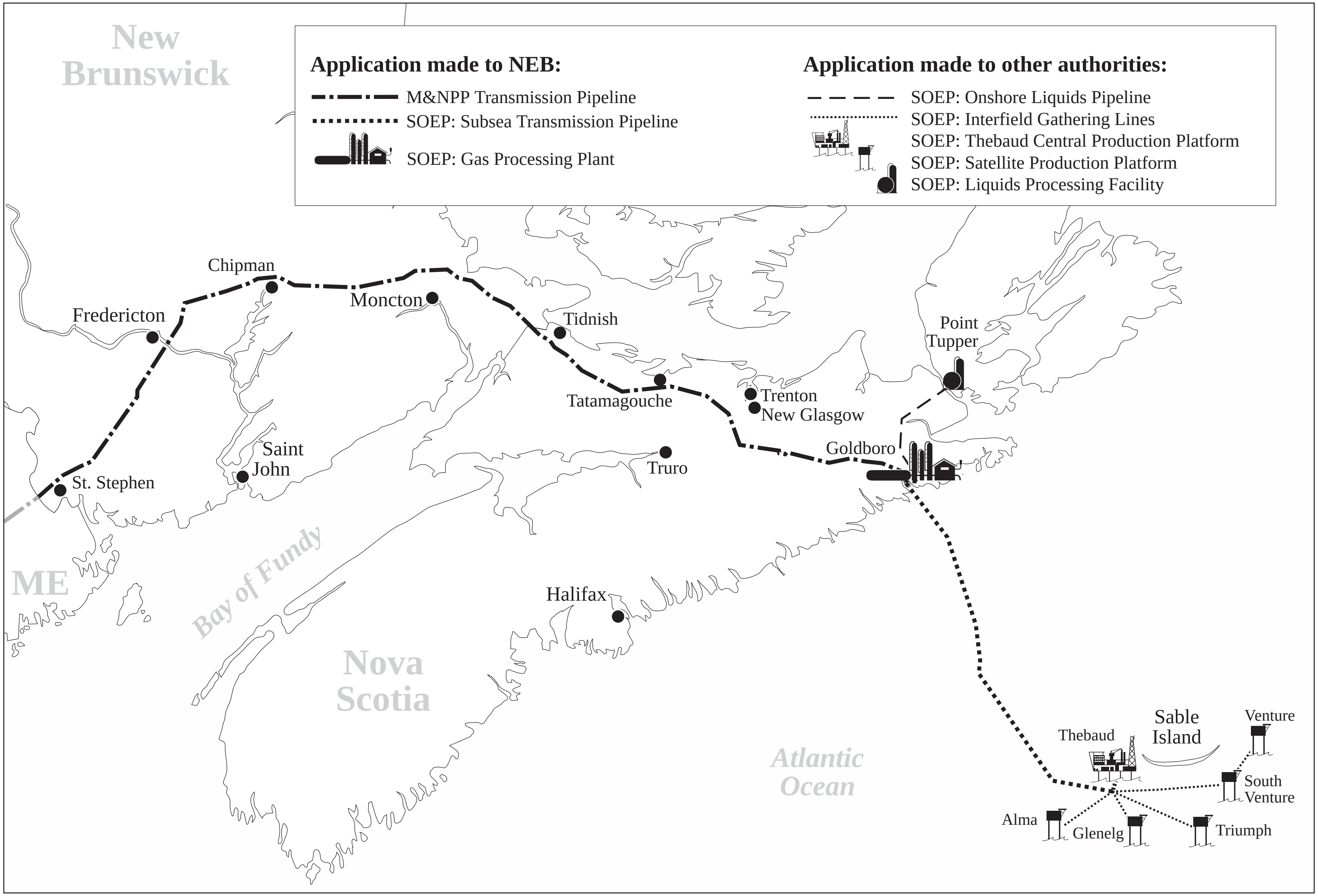
As previously mentioned in the foreword, the Terms of Reference, contained in the Agreement, stipulated that the Review procedures set by the Joint Review Panel would include the *NEB Rules of Practice and Procedure* which contemplate sworn testimony, cross-examination and argument. Many of the issues relating to SOEP and to M&NPP were the same or interdependent, as were many of the specific issues to be considered by the Joint Public Review Panel, the NEB panel and the Commissioner. The Joint Review Panel, the NEB panel and the Commissioner therefore decided to hear evidence and argument, relevant to their respective mandates, with respect to both SOEP and M&NPP in a single consolidated proceeding. The "Directions on Procedure", to that effect, were issued by the Joint Review Panel on 16 December 1996 as was the NEB Hearing Order, GH-6-96.

Applications by SOEP and M&NPP to the NEB were for Certificates of Public Convenience and Necessity under section 52 of the *NEB Act* for the facilities under NEB jurisdiction, which include: the offshore pipeline from the central processing facility at Thebaud to landfall; the onshore line from landfall to the gas plant at Goldboro, Nova Scotia; the slugcatcher and gas processing facilities at Goldboro; and, the 558 kilometres of 762 millimetre pipeline and associated facilities extending from the outlet point of the Goldboro gas plant to the international border near St. Stephen, New Brunswick. As well, application was made for an Order under Part IV of the *NEB Act* respecting pipeline tolls and tariffs.

The responsibility for the approval of the detailed design and matters related to the detailed design for the central processing facility at Thebaud, the unmanned satellite platforms at the remaining five gas fields, the interfield flowlines and the drilling activity required for the gas field development rests with the CNSOPB. Discussion and review of these matters will be part of their subsequent Decision Report on the Development Plan Application.

The responsibility for the approval of the detailed design and matters related to the detailed design for the natural gas liquids pipeline and the natural gas liquids facilities at Point Tupper, Nova Scotia rests with the province. Discussion and review of these matters will be part of their subsequent regulatory permitting and reporting.

Figure 1-1
The SOEP and M&NPP Projects



Chapter 2

The Joint Review Panel Report Summary and Conclusions

(This chapter is taken directly from the Joint Review Panel Report)

The Joint Review Panel (the Panel) after taking account of the evidence, cross-examination, argument and public comments during its examination of the Sable Offshore Energy Project (SOEP) and the Maritimes and Northeast Pipeline Project (M&NPP), concludes that SOEP and M&NPP are not likely to cause significant adverse environmental effects, provided that appropriate mitigation identified in the course of the review proceedings is applied to both Projects and that the Panel's recommendations are followed and implemented. As well, the Panel concludes that the socio-economic outcomes are favourable for the Maritimes and Canada. As a consequence, the Panel encourages the appropriate regulatory authorities to proceed with all necessary approvals for SOEP and M&NPP without further delay.

In reaching its conclusions, the Panel had for its review information gathered from twenty information and scoping sessions held throughout Nova Scotia and New Brunswick, 1270 exhibits representing either direct written evidence or responses to formal information requests, and a total of 12,266 pages of transcripts from the 56 hearing days in Halifax and Fredericton.

Alternatives

Prior to the start of the hearings, a motion was put forward by Trans Québec and Maritimes Pipeline Inc. (TQM) to request that the Panel consider their proposal as an alternative to M&NPP and allow for a full environmental assessment of the TQM Pipeline Project, and that the National Energy Board (NEB) panel delay any decision on M&NPP until TQM's proposal has been heard. In addition, the Panel heard arguments from Tatham Offshore Inc. and Seafloor Structures Consulting Ltd. requesting that their proposals be considered as alternatives.

The Panel considered whether procedural fairness required it to delay issuance of its Report in order to conduct a comparative environmental assessment of the alternatives to the Projects under review. The Panel believes that it has satisfied its obligations in this regard through the 56 day hearing convened to examine the SOEP and M&NPP Applications, which includes evidence submitted with respect to alternatives to the Project. In view of this, the Panel concludes that it would be inappropriate to delay its report in order to embark upon multiple environmental assessments of potential alternatives. In addition, the NEB panel has also decided to reject requests for delay.

Offshore Environment

In reaching its conclusion with regard to significant adverse effects, the Panel considered many issues, both environmental and socio-economic. A major concern was the Proponents' introduction of waste discharges into the marine environment, particularly drill cuttings with their attendant residues of oil base drilling muds.

Based on the evidence presented, the Panel believes that SOEP's proposed methodology for the treatment and discharge of drilling and production wastes will not result in significant adverse effects to the Scotian Shelf. The Panel notes that SOEP has stated that it will meet or fall well below the limits outlined in the "Offshore Waste Treatment Guidelines" for hydrocarbon content in liquid wastes and on drill solids. The Panel recognizes the importance of monitoring platform discharges.

Accordingly, it has provided recommendations to ensure that SOEP implement adequate monitoring and to encourage the incorporation of new drilling waste management technologies when they become available, if they are proven to be environmentally sound and economically feasible.

Another major concern was the possible impacts of the Project on the Gully, an area of special ecological significance on the Scotian Shelf. Concerns were raised regarding the impact of platform discharges and noise generated by Project- related activities potentially reaching the Gully. An additional concern that emerged was that future project expansion might lead to developments even closer to the Gully.

The Panel is concerned over the possibility of project expansion encroaching on the Gully. It has concluded that additional research must be conducted to obtain baseline data on water circulation, sediment transport and acoustic transmission effects on marine mammals. Accordingly, the Panel recommends that, prior to regulatory approval, SOEP submit its Code of Practice outlining protection measures for the Gully as part of their final Environmental Protection Plan. Included in the Code will be details on proposed monitoring programs and mitigative measures. The Panel further recommends that SOEP initiate or contribute to research activities that will provide the baseline data necessary for Environmental Effects Monitoring programs. Additional data are essential to permit effective decision-making with regard to further development of the resource, particularly at sites nearer to the Gully.

The impact of onshore and offshore construction activities on the aquaculture industry raised a number of issues, particularly in the area of Country Harbour, Nova Scotia. Blasting and trenching near the pipeline landfall raised concerns as to the potential for re-suspension of sediments. The siting of supply or service bases near Country Harbour was also raised. Increased vessel traffic associated with these bases could seriously impact on current aquaculture leases in the area. Of particular importance to the industry was the possibility of actual or perceived tainting, given that consumers view Country Harbour as a pristine marine environment.

The Panel was concerned here as well about the lack of baseline data regarding possible adverse effects on the aquaculture industry. Accordingly, it recommends that SOEP commit to a minimum of one full year of baseline water and sediment monitoring. As to the potential impact of supply or service bases on the aquaculture industry near Country Harbour, the Panel recommends that SOEP remove Country Harbour from consideration as a base site.

Onshore Environment

Onshore issues of particular importance to both the SOEP and M&NPP proposals included watercourse crossings, of which 260 are anticipated, and the potential impact of acid generating rock. Issues arising from watercrossing activities were focussed on potential adverse effects on fish and fish habitat. Blasting and excavation can expose acid generating rock, which can increase acid levels in the aquatic environment, thereby adversely affecting some organisms. Special emphasis was directed at the adverse impacts on salmon.

The Panel recommends that SOEP and M&NPP mitigate potential Project impacts by addressing: watercourse crossing methods; wet weather shut-down policy; construction techniques and mitigative measures; methods to deal with mitigation of acid generating rock; and finally, new environmental issues resulting from construction activities.

Route selection and land use conflicts were additional areas of concern. The Panel believes that the M&NPP route selection process was thorough and involved considerable public participation. The proposed general route for M&NPP is adequate, if proper mitigative measures are followed. Moreover a detailed 25 metre route will be identified and studied further. This should afford further opportunities for avoidance or mitigation of any sensitive environmental areas and address any new or remaining concerns which were raised by aboriginal and environmental interests. It will also permit persons who believe that their lands may be adversely affected to make their views known and ensure that their rights are protected.

The Panel recognizes that many rural residents fear that the presence of a pipeline will detract from the rural quality of life. It heard concerns during scoping and information sessions on matters such as pipeline safety, adverse effects on wildlife, property trespass and the aesthetics of right-of-ways. The Panel recognizes their validity but feels that the evidence before it indicates that these kinds of impacts can be avoided or mitigated to insignificance through proper planning, construction and maintenance practices. SOEP and M&NPP have committed to ensure that there will be no significant adverse impacts and the Panel has provided recommendations to ensure this happens.

Socio-Economic

Issues brought forth in the Hearing were not limited to environmental matters alone; they included many areas related to socio-economic effects and benefits. One issue of some importance was the adequacy of the public consultation program, which is required by the NEB and by the environmental assessment legislation of Nova Scotia and Canada. The Panel found SOEP and M&NPP's programs to be extensive, and it was satisfied with their overall effectiveness. One exception was the inadequate initial contact with the aboriginal community.

Jobs and business opportunities were a concern. The Panel found that direct construction benefits will be short-term and limited, especially when compared to overall economic activity in the Maritimes. The benefits will be real and welcome but they will not be an economic panacea.

The main economic benefits lie in the future. Attaining these benefits will depend on SOEP and M&NPP acting as a catalyst to further hydrocarbon exploration and development. Attainment of that goal will provide an energy alternative for existing industry as well as providing a stimulus for new industrial development, especially in the area of petrochemicals.

The Panel believes that more could be done to enhance opportunities in the Maritimes. In particular, there is no commitment to process gas liquids in Nova Scotia. They appear to be destined solely for export markets. The Panel sees industrial development opportunities arising from the availability of natural gas and its liquid by-products. The Panel was also struck by a lack of foresight in developing training programs in anticipation of the increased economic activity that a 'seed' project will generate. A similar concern was the absence of a long range research and development program. Such a program will be needed to provide a requisite environmental and socio-economic information base for future regulatory decisions and to ensure that the Canada and Nova Scotia capture as many future benefits as possible.

Markets and Tolls

From the perspective of the Panel, a primary objective of SOEP and M&NPP is to provide access to natural gas for the Maritimes markets. At the same time, the Panel recognizes that markets in the U.S. northeast are a prerequisite to the success of the Projects.

Further, the Panel is of the view that the appropriate toll design is linked to several market development factors. First, SOEP and M&NPP are seed projects, which will provide the foundation for future activity. Second, the building of laterals will encourage access to and growth of natural gas markets in the Maritimes. Third, while preserving the overall economic viability of the pipeline, it is important to recognize the relative economic position of different groups of shippers.

Because of the importance the Panel places on use of Sable gas in the Maritimes, it is inclined to look at the toll design and laterals policy as a "package". The Panel was attracted to M&NPP's postage stamp toll design methodology and Lateral Policy on the basis that it would provide a solid economic foundation for the pipeline in its early years and the greatest potential for the development of the Maritimes market through M&NPP's Lateral Policy.

While the Panel recognizes that the Province of Nova Scotia withdrew their support for the "Joint Position" in reply argument, it is of the view that the Joint Position provides the best available package for promoting gas market development in the Maritimes and, through discounts, partially recognizes the Nova Scotia position that distance should be a factor in toll design.

Nova Scotia intervenors were also opposed to the commitment by SOEP to sell the entire gas production from the first six Sable fields exclusively to M&NPP shippers. They argued that because of their proximity to the Goldboro gas plant, they should not be required to become shippers on the M&NPP pipeline in order to have access to Sable gas. While recognizing that sufficient gas production must be available to M&NPP to make the pipeline economic, the Panel will not sanction tied sales by SOEP because it believes that access to natural gas for Canadians should not be conditional on buyers/shippers transporting their gas on designated facilities.

The Panel believes that the option of by-passing the M&NPP pipeline addresses Nova Scotia interests in arranging their own transportation, while preserving the prerequisite capacity to serve the U.S. northeast.

Monitoring

Natural gas production and transportation will bring new challenges to the Maritimes, but they are not dissimilar to those faced in the past 25 years of offshore petroleum exploration and production. Projects require detailed planning for the proposed operations prior to construction, and thereafter, effective inspection, monitoring and enforcement programs. Planning for SOEP and M&NPP is still evolving. The Panel in making its recommendations is aware that in some instances it has assessed principles rather than details. This is the nature of the offshore development process. Inspection, monitoring and enforcement are tools that guarantee that a project will be built and operated according to plan. The Panel has recommended a number of safeguards to ensure that any modifications to plans result in greater safety, less environmental impact and more benefits. The Panel has, to the best of its ability, ensured that effective inspection and enforcement mechanisms are in place, consistent with the precautionary principle which ensures a conservative approach to environmental protection. It has also supported mechanisms by SOEP and M&NPP to encourage monitoring through continuing dialogue and input from the public, stakeholders, regulators and special interest groups. SOEP and M&NPP have initiated a range of consultative committees and the Panel has suggested how these committee mechanisms can be improved. Committees offer a meaningful opportunity to monitor work in progress and ensure that local and special concerns are addressed. The Panel recognizes the efforts that SOEP and M&NPP have taken to date and encourages them to build on these for the future.

Chapter 3

The Sable Offshore Energy Project

3.1 Description

The proposed two-phase production gathering pipeline from the Thebaud platform to the Goldboro gas plant will be approximately 208 kilometres in length. The pipe will be 660 millimetres in diameter, with a wall thickness of 17.48 millimetres, and has been designed with excess capacity in order to provide for future expansion of the offshore production facilities. The design pressure for the pipeline will be approximately 15,300 kPa, in accordance with the "CSA Z662-96, Oil and Gas Pipeline Systems, December 1996" specifications, and the maximum operating pressure will be approximately 11,700 kPa. The pipeline will be externally coated with a fusion bond enamel and cathodically protected against corrosion. The Proponents also considered coating the pipe with concrete to provide increased weight stability, but a final decision on this option has yet to be made.

The subsea pipeline corridor was selected on the basis of distance, slope, water depth and the avoidance of unsuitable substrate materials. The line will be routed, where possible, to avoid extreme water depths in order to simplify lay barge requirements and to avoid rock outcrops and severe slopes. The Proponents expect that the pipeline will be trenched in shallow water and, in many cases, that it will self bury. Design criteria for burial will be refined in forthcoming geotechnical studies.

The proposed onshore facilities will include a slugcatcher and a natural gas processing plant to be located in Goldboro, as well as a natural gas liquids processing facility to be located in the Point Tupper area. The gas plant will produce specification sales gas and unstabilized liquid products. These liquids will be shipped by pipeline to Point Tupper where production of specification liquefied petroleum gases and stabilized condensate will occur.

The Goldboro gas plant will have the capacity to process approximately 17.0 million cubic metres per day of raw inlet natural gas and to remove 3,849 cubic metres per day of natural gas liquids. The actual volumes of product shipped will vary according to production practices.

3.2 Environment and Socio-Economic Matters

Decision

The Board has considered the Joint Public Review Panel Report and the Government of Canada's response thereto, and is of the view that, taking into account the implementation of appropriate mitigation measures identified in the course of the Joint Panel Review proceedings, the portions of the Sable Offshore Energy Project under its jurisdiction are not likely to cause significant adverse environmental effects. Further, the socio-economic outcomes will be favourable to the Maritimes and Canada.

3.3 Facilities

Decision

Based on the information filed during these proceedings, the Board is satisfied with the design and configuration of the SOEP facilities. SOEP will be required to submit, for Board approval, information relevant to the final design of the offshore pipeline well in advance of actual construction. Further, SOEP will be required to seek approval pursuant to section 47 of the *NEB Act* for leave to open the offshore pipeline, the gas plant and associated facilities.

3.4 Economic Matters

Supply

A total of 121 test wells have been drilled on the Scotian Shelf since 1959. The CNSOPB has issued 22 Significant Discovery Licenses for fields considered to have potential commercial viability. These sites are estimated to contain a total of 163 billion cubic metres of recoverable gas.

The SOEP proponents submitted an application based on the proposed development of six fields on the Scotian Shelf: Alma, Glenelg, North Triumph, Venture, South Venture and Thebaud. These six fields have mean expected raw recoverable gas of 84.3 billion cubic metres and a 10 percent probability that the reserves will exceed 145.1 billion cubic metres. The proponents identified this six-field development as a "seed project" for future development. Additional information on supply can be found at pages 16 and 62-63 of the Joint Review Panel Report.

Markets

The ultimate markets for the SOEP-supplied gas are located in eastern Canada and the U.S. northeast where the gas would displace higher-priced fuels as well as serve incremental markets. A full discussion of both domestic and export markets can be found in Chapter 4 and on pages 64 and 65 of the Joint Review Panel Report.

Tolls & Method of Regulation

At the outset and for an indeterminate period, SOEP will be the sole user of the offshore transportation and onshore gas processing facilities. Since it will assume full ownership and operating costs of the facilities, SOEP will not charge a "toll" for transportation or processing service.

SOEP submitted that, because it would be the sole shipper on its line and no toll would be charged, there would be no need for the NEB to regulate its activities. Alternatively, it suggested that it be regulated as a Group 2 company on a complaints basis. Further, SOEP requested relief from the following accounting and financial reporting requirements: to keep its book of accounts pursuant to the code of accounts prescribed in the *Uniform Accounting Regulations*; to file audited financial statements; to file a tariff; to file detailed information to support a tariff specified in Part X of the NEB's "Guidelines for Filing Requirements"; and to comply with the *Toll Information Regulations*.

Financing

The companies participating in SOEP have substantial assets in Canada and around the world and will generate the funds necessary for the project internally or from third parties.

> **Decision**
>
> **After taking into account the evidence filed with respect to supply, markets, economic feasibility and financial matters, the Board concludes that the SOEP facilities can be financed and will be used and useful over their economic life.**
>
> **The SOEP operating entity will be designated as a Group 2 company for the purposes of regulation under the *NEB Act*. SOEP will be required to keep its book of accounts pursuant to the code of accounts prescribed in the *Uniform Accounting Regulations* and to file audited annual financial statements. Should a third party request service on SOEP's facilities, SOEP would be required to file a tariff and toll schedules pursuant to subsection 60(1) of the *NEB Act*. Further, this tariff would include the explanatory note set out in Schedule B of the "Memorandum of Guidance on the Regulation of Group 2 Companies" indicating that persons who cannot resolve traffic, toll, and tariff issues with the Company may file a complaint with the Board.**

Chapter 4

Maritimes & Northeast Pipeline Project

4.1 Description

The proposed Maritimes & Northeast Pipeline Project (M&NPP) will consist of 558 kilometres of pipeline, 762 millimetres in diameter, extending from the outlet point of the Goldboro gas plant, first in a northwesterly direction passing near New Glasgow and Tatamagouche, and crossing the Nova Scotia-New Brunswick border near Tidnish.

The pipeline will traverse New Brunswick in a westerly direction passing near Moncton and Chipman. From Chipman, it will proceed in a southwesterly direction passing near Fredericton, crossing the Saint John River and proceeding to the international border near St. Stephen, New Brunswick. Approximately 234 kilometres of pipeline will be located in Nova Scotia and approximately 324 kilometres of pipeline will be located in New Brunswick.

The pipeline will be designed, installed and operated in accordance with the Board's *Onshore Pipeline Regulations*, which specify that the design, installation, testing and operation of a pipeline be in accordance with the applicable provisions of the "Canadian Standards Association Z662, Oil and Gas Pipeline Systems".

The proposed facilities include a custody transfer meter station located at the pipe inlet, three pig launchers and two pig receiver traps. Also included in the design are mainline valves, located at a nominal 40 kilometre spacing, and side valves for the future connection of laterals.

The pipeline will be designed to accommodate an initial forecast of 530,000 MMBtu (million British thermal units) of peak day capacity and, with additional compression, the peak day capacity could be increased to over of 800,000 MMBtu.

4.2 Environment and Socio-Economic Matters

Decision

The Board has considered the Joint Review Panel Report and the Government of Canada's response thereto, and is of the view that, taking into account the implementation of appropriate mitigation measures identified in the course of the Joint Panel Review proceedings, M&NPP is not likely to cause significant adverse environmental effects. Further, the socio-economic outcomes will be favourable to the Maritimes and Canada.

4.3 Facilities

Decision

Based on the information filed during these proceedings, the Board is satisfied with the design and configuration of the M&NPP facilities. Before initiating service, the company operating the pipeline will be required to seek approval pursuant to section 47 of the *NEB Act* for leave to open the pipeline.

4.4 Economic Matters

Supply

The supply for M&NPP will come from SOEP, as discussed in Chapter 3. More information on the supply available to M&NPP can be found at pages 16 and 62-63 of the Joint Review Panel Report.

Markets

Sable-sourced gas is expected to serve incremental and displacement industrial, Local Distribution Company (LDC), marketer, and power generation markets in Canada and in the U.S. The northeast U.S. market is considered to be the anchor market for SOEP and M&NPP.

Based on the NEB’s "1994 Energy Supply and Demand Report", total energy demand in Nova Scotia and New Brunswick is forecast to grow at an average annual rate of approximately one percent between the years 1991 and 2010. M&NPP submitted that the construction of the SOEP and M&NPP facilities and downstream distribution systems will provide the necessary catalyst for the development and growth of these domestic markets.

To demonstrate the long-term nature of gas demand in the U.S. northeast market, M&NPP relied on a forecast, prepared by the Reed Consulting Group, entitled "Assessment of the Market for Natural Gas in the Northeast United States". This study concluded that total gas demand (i.e. firm throughput, interruptible, and electric power) in the U.S. northeast is forecast to increase from 2,700 TBtu (trillion British Thermal units) in 1997 to 3,325 TBtu in 2006, an annual average increase of 2.3 percent. Most of this gas demand is directly accessible off the U.S. portion of the M&NPP system.

M&NPP entered into Precedent Agreements with domestic and export shippers totalling 640,000 MMBtu/d. In addition executed Precedent Agreements for 7,600 MMBtu/d and 100,000 MMBtu/d of OP 275 and OP 214 (offpeak) services, respectively, have also been executed.

M&NPP has executed 20-year Backstop Precedent Agreements with Mobil Natural Gas Inc. and Imperial Oil Resources Limited for all of the throughput on the M&NPP pipeline up to 440,000 MMBtu/d that is not subject to firm transportation Service Agreements entered into by other shippers. These Backstop Precedent Agreements take effect from the date of commencement of service, and include all capacity that might become available in the future as a result of the termination of such PAs or firm transportation Service Agreements prior to the end of the 20 years.

Financial Regulation

Toll Design and Lateral Policy

The M&NPP proponents applied for a joint toll design and Lateral Policy which it argued were inseparable. The toll design is a single postage-stamp rate for each of the services offered. The Lateral Policy would see laterals tolled on a rolled-in basis if they generated sufficient revenue to cover the annual cost of service. Should additional costs be added because of a lateral, the pipeline company would seek a contribution from the shipper.

During the hearing, a Joint Position on Tolling and Laterals (Joint Position) was negotiated between representatives of SOEP and M&NPP and the provinces of Nova Scotia and New Brunswick. The Joint Position supports the postage stamp toll design but offers discounts for deliveries in Nova Scotia and New Brunswick in the initial years of the project. Any revenue deficiency associated with these discounts would be offset though adjustments to the depreciation policy of the pipeline. The Joint Position supported M&NPP’s Lateral Policy and committed M&NPP’s proponents to build laterals to Halifax, Nova Scotia, and Saint John, New Brunswick. Further, the Joint Position committed the SOEP proponents to put aside 10,000 MMBtu/d of production for sale to LDCs in each province for the initial three years of production.

Method of Regulation

The M&NPP proponents indicated a preference for regulation on a complaint basis as provided by Group 2 status. However, the M&NPP proponents suggested that it might be more appropriate to reserve judgement on the designation of the pipeline for Group 1 or Group 2 status until a hearing on its final toll application is held.

Financing

The M&NPP partners intend to finance the project with a combination of funded long-term debt and equity injections from the partners. The long-term debt will be arranged based on support provided by the long-term transportation contracts and financial arrangements with producing companies.

> **Decisions**
>
> **After taking into account the information provided during this proceeding concerning supply, markets, economic feasibility and financial matters, the Board concludes that the M&NPP facilities can be financed, will be used and useful over their economic life, and that the associated tolls will be paid.**
>
> **The Board approves the forward test year cost of service methodology as appropriate for M&NPP. Maritimes and Northeast Pipeline Management Ltd. (M&NPML) is directed to file tolls which are designed using this methodology and incorporate the provisions respecting toll design and laterals as contained in the "Joint Position on Tolling and Laterals" filed as Appendix V of the Joint Review Panel Report. M&NPML will be regulated as a Group 1 company.**

Concerning the cost of equity capital, the Board agrees with the Joint Review Panel's statement, "...M&NPP can be viewed as having the same business risk as other Group 1 pipelines." However, the circumstances faced by M&NPP are substantially different from those faced by other pipelines regulated by the Board. It is a greenfield project, its only sources of gas are new and untested fields, it will be serving an untested market in Canada, and it is facing significant competition for its anchor market in the U.S. northeast. Consequently, the Board approves the combination of a 25 percent common equity portion coupled with a 13 percent rate of return on that equity as appropriate in the circumstances of this pipeline.

The Board notes that, should the circumstances change before the five years are up, any interested party may come before the Board to request a change in the financial structure and rate of return on equity for M&NPP.

Chapter 5

Disposition

The foregoing chapters constitute our Reasons for Decision in respect of the applications heard by the Board in the GH-6-96 proceedings. The Board has found that the Sable Offshore Energy Project facilities under its jurisdiction and the Maritimes & Northeast Pipeline Project will be required for the present and future public convenience and necessity, provided the conditions outlined in Appendices I and II are met. Therefore, the Board will seek approval from the Governor in Council for the issuance of certificates.

K. Vollman
Presiding Member

R. Fournier
Member

A. Côté-Verhaaf
Member

Calgary, Alberta
December 1997

Appendix I

Sable Offshore Energy Project Certificate Conditions

1. This Certificate of Public Convenience and Necessity shall be issued to and held by Mobil Oil Canada, Ltd. (the "Company") pending the establishment of the legal operating entity for the Sable Offshore Energy Project. Upon establishment of that legal entity, the Proponents will apply for permission to transfer this Certificate so that the pipeline facilities, in respect of which this Certificate is issued, shall be held and operated by that entity.

2. The Company shall implement or cause to be implemented all of the policies, practices, and procedures for the protection of the environment included in or referred to in its Application, in its undertakings made to relevant regulatory authorities, and as adduced in evidence before the Board in the GH-6-96 proceeding.

3. The Company shall, at least 60 working days prior to the commencement of construction of the nearshore pipeline in Betty's Cove, submit to the appropriate regulatory authorities for approval additional information regarding the proposed specific routes of the subsea pipeline and the specific installation method for the landfall point. The additional information shall set out:

   (a) the results of the sediment sampling program along the specific route into Betty's Cove;

   (b) an underwater habitat assessment along the specific route into Betty's Cove;

   (c) an environmental issues list identifying all relevant effects of the selected route on marine biological Valued Environmental Components;

   (d) the associated mitigation measures to render those environmental effects insignificant; and

   (e) the details on the selected installation method for the landfall point.

4. The Company shall conduct a minimum of one full year of baseline water and sediment quality monitoring prior to any trenching activity in Country Harbour. Furthermore, the results of this program and those of the sediment modelling study for Country Harbour shall be submitted to the Board and shall be made available for review by both the Fisheries Liaison Committee and the Department of Fisheries and Oceans. Any issues raised shall be addressed prior to the commencement of any trenching activity.

5. The Company shall, to the extent possible, conduct pipeline laying activity at Country Harbour and Country Island outside the mid-May to mid-August nesting season, particularly until the appropriate baseline data has been collected and analyzed on the roseate tern population in this area. This data shall be submitted to the Board.

6. The Company shall prepare detailed Contingency Plans (as part of the Environmental Protection Plan) which focus on spill prevention and response, and strategies for cleaning up the marine and terrestrial environments. These plans shall be submitted to the Board prior to the commencement of any fabrication or construction activity related to the offshore pipeline.

7. The Company shall empower their Environmental Inspector with the authority to terminate any onshore pipeline construction activities which impact negatively on fish and fish habitat.

8. The Company shall revisit its use of the upper limit of the Nova Scotia Noise Guidelines as the design criteria for the Goldboro gas plant. The Company shall carry out regular noise monitoring at the natural gas plant and add plant noise to its Environmental Issues List.

9. The Company shall submit to the Board a written protocol or agreement spelling out Proponent-Aboriginal roles and responsibilities for cooperation in studies and monitoring.

Offshore Pipeline

Prior to the Commencement of Construction

10. The Company shall submit to the Board, for review, at least one hundred and eighty (180) days prior to the commencement of installation:

    (a) the pipeline design data and the final pipeline design, including, but not limited to:

        (i) the final Offshore Pipeline Design Basis Memorandum;
        (ii) detailed materials specifications;
        (iii) any relevant supporting design studies;
        (iv) limits of unacceptable spans found during installation, testing and operation, and mitigation measures to be used if an unacceptable span was to develop; and
        (v) construction schematics.

    (b) a list of the regulations, standards, codes and specifications used in the design, construction and operation of the pipeline from the Thebaud Platform to the Goldboro gas plant, indicating the date of issue;

    (c) reports providing results and supporting data from any geotechnical field investigations for the evaluation of:

        (i) the potential for slope instability;
        (ii) the geotechnical and geological hazards and geothermal regimes which may be encountered during installation and operation of the facilities; and
        (iii) the special designs and measures required to safeguard the pipeline; and

    (d) the pipeline route detailed on appropriate scale maps, indicating all seabed, geotechnical and other features to a sufficient depth and resolution.

11. The Company shall not start any pipeline installation activity until the final pipeline design has been submitted to the Board for review.

12. Unless the Board otherwise directs, the Company shall submit, at least thirty (30) days prior to the commencement of construction, a detailed construction schedule. The Proponents shall provide the Board and all other appropriate regulatory authorities with regular updates on the progress of construction activities and with any changes in the schedule as the construction progresses.

13. The Company shall submit to the Board, for review, at least thirty (30) days prior to the commencement of construction, all construction manuals, including:

    (a) a pipe laying and pipe trenching manual (including, but not limited to, other pipeline construction activities such as pipeline stabilization or anchoring);

    (b) a construction safety manual (containing appropriate procedures for the reporting of any incidents to the Board);

    (c) a pipeline emergency response procedures manual; and

    (d) all other manuals relevant to construction, installation and operation of the subsea gathering line from the Thebaud Platform to the Goldboro gas plant.

During Construction

14. Unless the Board otherwise directs, the Company shall, during construction, for audit purposes, maintain at each construction site a copy of the welding procedures and non-destructive testing procedures used on the project together with all supporting documentation.

Post Construction

15. The Company shall file with the Board, no later than one hundred and eighty (180) days after the completion of the pipe laying, an as-laid pipeline survey report and maps.

16. The Company shall submit to the Board, for review, at least thirty (30) days prior to "Leave to Open", an operation and maintenance manual including, but not limited to, inspection and remedial correction procedures for seabed movements causing spanning.

17. If the Board determines that the pipeline design assumptions, relative to pipeline burial, pipeline stability and seabed changes, cannot be confirmed, the Company shall submit to the Board, for review, at least one hundred and eighty (180) days prior to leave to open, a pipeline in-place monitoring program. This program shall include all the inspection procedures and schedules, and criteria that will initiate specific inspection and remedial action procedures (such as storm conditions and limiting span lengths). This program will also identify all equipment required on-site or near-site for remedial action procedures, as well as any such equipment that has to be brought from remote locations. The program shall include the procedures for reporting incidents to the Board.

Goldboro Gas Plant

18. Unless the Board otherwise directs, the Company shall:

(a) cause the gas plant facilities to be designed, manufactured, located, constructed and installed in accordance with those specifications, drawings, and other information set forth in its application, or as otherwise adduced in evidence before the Board;

(b) within thirty (30) days of the issuance of this Certificate, submit to the Board for review an abbreviated design information package of the gas plant containing:

(i) process flows, with temperatures, pressures, mass balances, capacity and energy requirements of compressors, heaters, and turbo-expanders; and
(ii) codes, standards and material specifications, to be used (for major equipment and piping);

(c) make no variation to the specifications, drawings or other information or data referred to in subparagraphs 18(a) and 18(b) without the prior approval of the Board; and

(d) design, fabricate and install all of the components of the gas plant in accordance with the codes and standards of the Province of Nova Scotia which are adopted by reference in this Certificate.

Quality Assurance and Construction

19. Unless the Board otherwise directs, the Company shall file with the Board for its approval, at least ninety (90) days prior to the proposed date for the commencement of construction of the gas plant authorized by this Certificate:

(a) a design information package of the gas plant containing:

(i) process flows, with temperatures, pressures, mass balances, and equipment energy requirements;
(ii) piping and instrumentation diagrams for all plant systems;
(iii) material specifications to be used.

(b) a description of any changes in the gas plant design from that indicated at the hearing or in the abbreviated design information package submitted pursuant to subparagraph 18(b);

(c) a list of the names and sections of the codes and standards to which the gas plant will be designed, fabricated and constructed;

(d) the procedures for project quality assurance, quality control and cost control in the design, fabrication and construction of the gas plant, including audit and corrective action procedures; and

(e) the pressure piping and pressure vessel, non-destructive and pressure testing program including audit and corrective action procedures.

Construction and Operational Safety

20. Unless the Board otherwise directs, the Company shall:

(a) review with the appropriate regulators the results of all their Process Hazard Assessments within thirty (30) days of their completion. The Goldboro gas plant's Process Hazard Analysis shall be completed and reviewed with the appropriate regulators at least thirty (30) working days before final design freeze; and

(b) At least sixty (60) days prior to the commencement of construction of the approved facilities, file with the Board for review:

(i) a detailed construction schedule or schedules identifying major construction activities and shall notify the Board of any modifications to the schedule or schedules as they occur; and

(ii) a construction schedule safety addendum, detailing the management of safety for all employees on site, for each phase of the construction.

During Construction

21. Unless the Board otherwise directs, the Company shall, during construction of the gas plant, file with the Board monthly construction progress and cost reports, in a format to be determined through consultation with Board staff, providing a breakdown, by plant process system, location and facility, of costs incurred during that month, the percentage of each activity which has been completed and an update of costs to complete the project.

22. Unless the Board otherwise directs, the Company shall, during construction of the gas plant, maintain for audit purposes at each construction site, a copy of the welding procedures and non-destructive testing procedures used on the project together with all supporting documentation.

Prior to Leave to Open

23. Unless the Board otherwise directs, the Company shall, prior to applying for leave to open for any segment of the gas processing facilities authorized by this Certificate, file with the Board for its approval:

(a) its specifications and procedures for the operation, maintenance, repair, and abandonment of the Goldboro gas plant as established pursuant to section 48 of the *Onshore Pipeline Regulations*. The existence of, and the detail of any operation, maintenance or repair procedure shall be defensible in relation to the system or equipment Process Hazard Analysis;

(b) a detailed explanation of the programs for monitoring the internal and external conditions of the pressure retaining equipment in the gas plant authorized by this Certificate, having particular regard to those parts of the gas plant with the potential to cause danger to the employees, the public and the environment; and

(c) a detailed training program, based at least in part on the gas plant's Process Hazard Analysis, wherein audits can verify competency of the employee before the assignment of the task.

Prior to Commissioning and Start-Up

24. Unless the Board otherwise directs, the Company shall conduct a "Pre-Commissioning Safety Audit" of all gas plant facilities, and shall submit the results of the audit to the Board for review prior to undertaking the commissioning of the gas plant.

Prior to Equipment Custody Turn-Over or Commissioning

25. Unless the Board otherwise directs, the Company shall, at least sixty (60) days prior to turn-over or commissioning of any gas plant equipment, submit for review:

(a) the turn-over, commissioning, and start-up procedures and schedules for all plant equipment. Include information regarding the estimated number and location of persons on site during each of the commissioning and start-up procedures; and

(b) the turn-over, or commissioning safety management policies and procedures, showing how the safety of all the employees and the public will be ensured during the commissioning phases of the gas plant.

26. Unless the Board otherwise directs, the Company shall submit for approval at least sixty (60) days prior to commencing plant operations:

(a) an operations and maintenance manual pursuant to section 48 of Part VII of the *Onshore Pipeline Regulations* which shall include all the safe work procedures required to maintain, commission, start-up, operate, and shutdown all equipment in, and associated with, the gas plant;

(b) a gas plant specific emergency response procedures manual; and

(c) contingency plans for hydrocarbon releases to atmosphere within the gas plant and related facilities.

Post Construction

27. Unless the Board otherwise directs, the Company shall, within one-hundred and eighty (180) days of putting the additional gas plant facilities into service, file with the Board a report providing a breakdown of the costs incurred in the construction of the gas processing facilities, in a format similar to that used in Schedules 4 through 15 of subtab 9 under Tab "Facilities" of Exhibit B-1 of the GH-3-96 proceeding, setting forth actual versus estimated costs, including reasons for significant differences from estimates.

Gas Plant Operation

28. Unless the Board otherwise directs, the operators of the Goldboro gas plant shall ensure that the plant is operated in accordance with environmental protection codes, and standards approved or adopted by the Province of Nova Scotia which are adopted by reference in this document.

29. Unless the Board otherwise directs, the operators of the Goldboro gas plant will at least once per quarter allow, after at least 24 hours prior notice, representatives of the provincial environmental protection branch onto the gas plant site to inspect, audit or verify the installation or calibration of those metering, measuring and sample collection devices required to compile environmental compliance data that will be used by the Company to show compliance with applicable regulations.

30. Unless the Board otherwise directs, the operators of the Goldboro gas plant shall ensure that all modifications, repairs and expansions conform to the applicable codes or standards that are approved or adopted by the Province of Nova Scotia from time to time, which are adopted by reference in this document.

General Condition

31. Unless the Board otherwise directs prior to 31 December 2000, this Certificate shall expire on 31 December 2000, unless the construction and installation of the offshore pipeline facilities has commenced by that date.

Appendix II

Maritimes & Northeast Pipeline Project Certificate Conditions

1. Unless the Board otherwise directs, the pipeline facilities in respect of which this Certificate is issued shall be the property of and shall be operated by Maritimes & Northeast Pipeline Management Ltd. (the "Company") on behalf of Maritimes & Northeast Pipeline Limited Partnership.

2. The Company shall implement or cause to be implemented all of the policies, practices, and procedures for the protection of the environment included in or referred to in its Application, in its undertakings made to relevant regulatory authorities, and as adduced in evidence before the Board in the GH-6-96 proceeding.

3. Unless the Board otherwise directs, the Company shall:

    (a) cause the approved facilities to be designed, manufactured, located, constructed and installed in accordance with those specifications, drawings and other information or data set forth in its application, or as otherwise adduced in evidence before the Board, except as varied in accordance with subsection (b) hereof; and

    (b) cause no variation to be made to the specifications, drawings or other information or data referred to in subsection (a) without the prior approval of the Board.

4. Unless the Board otherwise directs, at least ninety (90) days prior to applying for leave to open for any segment of the pipeline facilities authorized by this Certificate, the Company shall file with the Board, for its approval, operations and maintenance manuals and emergency response plans in accordance with sections 48 and 49 of the *Onshore Pipeline Regulations*.

Prior to the Commencement of Construction

5. Unless the Board otherwise directs, at least ten (10) days prior to the commencement of construction of the approved facilities, the Company shall file with the Board a detailed construction schedule or schedules identifying major construction activities and shall notify the Board of any modifications to the schedule or schedules as they occur.

6. Unless the Board otherwise directs, at least ninety (90) days prior to the commencement of construction, the Company shall submit reports satisfactory to the Board providing results and supporting data from any geotechnical and hydrological field investigations for the evaluation of:

    (a) the potential for slope instability;

    (b) water crossings and the approaches thereto;

(c) the presence of acid generating rock; and

(d) the presence of, or the potential for, the formation of, sink holes.

7. Unless the Board otherwise directs, at least ninety (90) days prior to the commencement of construction of the pipeline authorized by this Certificate, the Company shall file with the Board for approval:

(a) the final design for the pipeline, including a description of any changes in the pipeline design from that submitted at the hearing set down by Order GH-6-96; and

(b) the procedures for project cost control in the construction of the pipeline authorized by this Certificate.

8. The Company shall, at least sixty (60) days prior to construction, submit to the Board construction plans for each watercourse crossing site. The construction plans shall:

(a) be prepared in consultation with the appropriate regulatory agencies;

(b) include a consideration of all salmon rivers which will be crossed by the pipeline;

(c) as a minimum, include consideration of erosion and sedimentation control, blasting requirements, habitat restoration and site restoration as required, but may refer to standard drawings or specifications as appropriate; and

(d) be provided to interested parties for comment.

9. The Company shall, at least sixty (60) days prior to construction, prepare a report on the scheduling of water crossings in cooperation with appropriate regulatory authorities. The report shall discuss back-up measures to resolve potential problems. The report shall be made available to all interested parties who request a copy. Furthermore, the Company shall, at least 30 working days prior to the commencement of construction of the pipeline, submit to the Board for approval, additional information regarding the stream crossings. The additional information shall set out:

(a) the construction designs of the crossings;

(b) the proposed duration of the crossings;

(c) in-stream timing restrictions identified by regulatory agencies;

(d) an erosion and sediment control plan;

(e) the site-specific mitigative and restorative measures to be employed as a result of consultations with regulatory agencies;

(f) if a directional drilling method is used, the detailed drilling fluid plan addressing the methods of drilling fluid containment and storage, and specific methods for disposing of and/or recycling of the drilling fluids;

(g) if blasting is required, the blasting plan, including comments from the Department of Fisheries and Oceans;

(h) the evidence to demonstrate that all issues raised by regulatory agencies have been adequately addressed, including all necessary updates to the environmental assessments where deficiencies have been identified;

(i) the evidence to demonstrate that the proposed construction method and site-specific mitigative and restorative measures are in compliance with federal and provincial legislation; and

(j) the status of approvals, including environmental conditions.

10. The Company shall, at least thirty (30) days prior to the commencement of construction, file with the Board the results of the acid generating rock studies, including any locations which would be affected by construction, the proposed mitigation measures, monitoring requirements and the results of consultation with provincial authorities.

11. The Company shall, at least thirty (30) working days prior to the commencement of construction of the pipeline, submit to the Board for approval additional information regarding the treatment method to deal with acid drainage and specific mitigative measures to be implemented at stream crossings. The additional information shall set out for each stream crossing to be affected:

(a) the name and location of the stream;

(b) the selected treatment method of the runoff water;

(c) the proposed Canadian Water Quality Guideline values to be adhered to;

(d) the site-specific mitigative and restorative measures to be employed as a result of consultation with regulatory agencies;

(e) the evidence to demonstrate that all issues raised by regulatory agencies and other interested parties have been adequately addressed, including all necessary updates to the environmental assessments where deficiencies have been identified; and

(f) the status of approvals, including environmental conditions.

12. The Company shall, at least one hundred and eighty (180) days prior to the commencement of any construction activity requiring regulatory approval, submit to the Board for approval the final Environmental Protection Plan. Details of the proposed specific route for the pipeline shall also be filed at that time, and shall include:

(a) the results of all pre-construction surveys to identify special status species/habitat along the proposed corridor, including specific measures to be implemented;

(b) an environmental issues list identifying all relevant effects of the selected route; and

(c) the associated mitigation measures to render those environmental effects insignificant.

During Construction

13. Unless the Board otherwise directs, the Company shall, during construction, maintain for audit purposes at each construction site, a copy of the welding procedures and non-destructive testing procedures used on the project together with all supporting documentation.

14. Unless the Board otherwise directs, during the construction period, each month the Company shall submit construction reports that are satisfactory to the Board which detail the progress and current status of the project.

Post Construction

15. Unless the Board otherwise directs, within one-hundred and eighty (180) days of putting the facilities into service, the Company shall file with the Board a report providing a breakdown of the costs incurred in the construction of the facilities, in a format that is satisfactory to the Board, setting forth actual versus estimated costs, including reasons for significant differences from estimates.

16. The Company shall file with the Board a post-construction environmental report within one hundred and eighty (180) days of the in-service date for the Project. The post-construction environmental report shall set out the environmental issues that have arisen and shall:

    (a) indicate the issues resolved as well as unresolved; and

    (b) describe the measures the Company proposes to take in respect of the unresolved issues.

17. The Company shall develop the Enviromental Protection Plan in consultation with government agencies, stakeholder groups, interested parties and landowners.

18. The Company shall implement an environmental compliance and monitoring program which would include the filing of post-construction environmental reports to address Project-related environmental issues.

19. The Company shall develop the operations, emergency response and environmental protection manuals in consultation with relevant agencies, stakeholders and the public. The manuals shall be filed with the Board.

20. The Company shall take all reasonable steps to avoid fragmenting natural and forested areas. The fragmentation of natural and forested areas shall be included in the Company's Issues List. This shall require consideration and follow-up on steps to be taken at the detailed route design and construction stages.

21. The Company shall, at least one hundred and eighty (180) days prior to construction, submit a traffic study for the Goldboro area to the Board.

22. The Company shall submit to the Board a written protocol or agreement spelling out Proponent-Aboriginal roles and responsibilities for cooperation in studies and monitoring.

23. The Company shall file with the Board, prior to the commencement of construction, the executed Backstop Precedent Agreements.

24. The Company shall file with the Board, prior to the commencement of service, all firm transportation Service Agreements.

25. Unless the Board otherwise directs, this Certificate shall expire on 31 December 2000 unless the construction and installation of the facilities authorized by this Certificate has commenced by that date.

National Energy Board

Reasons for Decision

Alliance Pipeline Ltd. on behalf of the Alliance Pipeline Limited Partnership

GH-3-97

November 1998

Facilities and Tolls & Tariffs

National Energy Board

Reasons for Decision

In the Matter of

Alliance Pipeline Ltd.
on behalf of the
Alliance Pipeline
Limited Partnership

Alliance Pipeline Project

Application dated 3 July 1997

GH-3-97

November 1998

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Abbreviations

ADOE	Alberta Department of Energy
AGA	American Gas Association
AHA	all-heat average
ANG	Alberta Natural Gas Company Ltd
ANR	ANR Pipeline Company
AOS	Authorized Overrun Service
the Accord	"Agreement on Natural Gas Pipeline Regulation, Competition and Change to Promote a Competitive Environment and Greater Customer Choice", dated 7 April 1998 and signed by the Canadian Association of Petroleum Producers, NOVA Corporation, NOVA Gas Transmission Ltd., the Small Explorers and Producers Association of Canada, and TransCanada PipeLines Limited
Agency	Canadian Environmental Assessment Agency
Alliance	Alliance Pipeline Ltd.
Amoco	Amoco Canada Petroleum Company Ltd.
the Applicant	Alliance Pipeline Ltd.
Aux Sable	Aux Sable Liquid Products LP
B.C.	British Columbia
BC Gas	BC Gas Utility Ltd.
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
Bcf/yr	billion cubic feet per year
Btu/scf	British thermal units per standard cubic foot
Btu/kWh	British thermal units per kilowatt-hour
Board	National Energy Board
^oC	degrees Celsius

CAPP	Canadian Association of Petroleum Producers
CCA	Consumers' Coalition of Alberta
CCPA	Canadian Chemical Producers' Association
CEAA	*Canadian Environmental Assessment Act*
cm	centimetre
COSEWIC	Committee on the Status of Endangered Wildlife in Canada
CSA	Canadian Standards Association
CSA Z662-96	CSA Z662-96 standard entitled *Oil and Gas Pipeline Systems*
CSR	Comprehensive Study Report
CVN	Charpy V-Notch
CanWest	CanWest Gas Supply Inc.
Cochin	Cochin Pipe Lines Ltd.
Consumers' Gas	Consumers' Gas Company Ltd.
the Company	Alliance Pipeline Ltd.
conv.	conventional
dBA	decibals (A-weighted sound level)
DFO	Fisheries and Oceans Canada
DWTT	drop weight tear test
Duke	Duke Energy Marketing Limited Partnership
EIA	(U.S.) Energy Information Administration
EUB	Alberta Energy and Utilities Board
°F	degrees Fahrenheit
FERC	(U.S.) Federal Energy Regulatory Commission
Fekete	Fekete Associates Inc.
Foothills	Foothills Pipe Lines Ltd.

GAIA	Green Alternatives Institute of Alberta
GISB	Gas Industry Standards Board
GJ	gigajoule
GLJ	Gilbert Laustsen Jung Associates Ltd.
GRI	Gas Research Institute
HGI	Heartland Gas Initiative
ha	hectare
HRIA/AIA	Historical Resource Impact Assessment/Archeological Impact Assessment
IEA	Indigenous Ecology Alliance
IGCAA	Industrial Gas Consumers Association of Alberta
ILI	in-line inspection
IPLE	IPL Energy Inc.
Imperial Oil	Imperial Oil Resources Ltd.
J	joule
km	kilometre
KP	kilometre post
kPa	kilopascal
LDC	local distribution company
m	metre
m/s	metres per second
m^3	cubic metre
m^3/d	cubic metres per day
m^3/yr	cubic metres per year
Mbpd	thousand barrels per day
Mcf	thousand cubic feet

MDT	minimum design temperature
MELP	British Columbia Ministry of Environment, Lands and Parks
MFL	magnetic flux leakage
MJ	megajoule
MJ/kWh	megajoule per kilowatt-hour
MJ/m^3	megajoule per cubic metre
mm	millimetre
MMBtu	million British thermal units
MMcf/d	million cubic feet per day
MOP	maximum operating pressure
MOU	Memorandum of Understanding
MPa	megapascal
MW	megawatt
Marenco	Marenco Energy Associates
Memorandum of Guidance	Board's *Memorandum of Guidance on the Regulation of Group 2 Companies*
NEB	National Energy Board
NEB Act	*National Energy Board Act*
NGL	natural gas liquid
NGTL	NOVA Gas Transmission Ltd.
NICOR	NICOR Inc.
NOVA Chemicals	NOVA Chemicals Ltd.
NUL	Northwestern Utilities Limited
NYMEX	New York Mercantile Exchange
Northern Border	Northern Border Pipeline Company
PRRD	Peace River Regional District

psi	pounds per square inch
Pan-Alberta	Pan-Alberta Gas Ltd.
PanCanadian	PanCanadian Petroleum Limited
ProGas	ProGas Limited
Project	Alliance Pipeline Project
RMEC	Rocky Mountain Ecosystem Coalition
RTM	real-time modelling
Reed	Reed Consulting Group
SCADA	supervisory control and data acquisition
SEPAC	Small Explorers and Producers Association of Canada
SMYS	specified minimum yield stress
SPC DWTT	static pre-cracked drop weight tear test
Sproule	Sproule Associates Limited
the Standard	CSA Z662-96 standard entitled *Oil and Gas Pipeline Systems*
Tcf	trillion cubic feet
TCPL	TransCanada PipeLines Limited
TransCanada Gas	TransCanada Gas Services
Treaty 8	Treaty 8 Tribal Association
U.S. or U.S.A.	United States of America
Union Gas	Union Gas Limited
WCC	Wisconsin Capacity Coalition
WCPG	Western Canada Producer Group
WCSB	Western Canada Sedimentary Basin
WEI	Westcoast Energy Inc.

Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* ("*NEB Act*") and the Regulations made thereunder;

AND IN THE MATTER OF an application dated 3 July 1997 by Alliance Pipeline Ltd., on behalf of the Alliance Pipeline Limited Partnership and pursuant to Parts III and IV of the *NEB Act*, for (i) a certificate of public convenience and necessity to construct and operate the Canadian portion of a proposed natural gas pipeline system from northeastern British Columbia and northwestern Alberta to the midwest United States and (ii) related toll and tariff authorizations;

IN THE MATTER OF National Energy Board Hearing Order GH-3-97;

HEARD in Calgary, Alberta on 17 to 21 and 26 November 1997, 6 to 9, 12 to 16, 19 to 23, and 26 to 30 January 1998, and 2 February 1998; in Regina, Saskatchewan on 4 and 5 February 1998; in Fort St. John, British Columbia on 11 to 13 February 1998; in Edmonton, Alberta on 17 and 18 February 1998; and in Calgary, Alberta on 23 to 27 February 1998, 2 to 5, 9, 11 to 13, 16, 18 to 20, 23 to 27, and 30 to 31 March 1998, 1 to 3, 6 to 8, 14 to 16, 20 to 24, and 27 to 30 April 1998, and 11 to 15 and 19 to 21 May 1998;

BEFORE:

K.W. Vollman	Presiding Member
A. Côté-Verhaaf	Member
C.M. Ozirny	Member

APPEARANCES:

C.K. Yates R.A. Neufeld F.M. Saville, Q.C. D.E. Crowther	Alliance Pipeline Ltd.
S. Arcand	Alexander First Nation
D.A. Holgate N.J. Schultz	Canadian Association of Petroleum Producers
L.L. Manning D. Goffin	Canadian Chemical Producers' Association
M. Posey	Federation of Alberta Naturalists
D. Opekokew V. Khaladkar	Federation of Saskatchewan Indian Nations; the Chiefs of the Treaty No. 4 and Treaty No. 6 First Nations
M. Oldershaw	Green Alternatives Institute of Alberta

T. Hall	Indigenous Ecology Alliance
N.J. McKenzie	Industrial Gas Consumers Association of Alberta
D. Bursey W.M. Moreland	IPL Energy Inc. (now Enbridge Inc.)
J. Yardley M. Stewart K. Goodings	Peace River Regional District
M.D. Sawyer G. Hunt N. Conrad	Rocky Mountain Ecosystem Coalition
E. Wolf	Native Canadian Petroleum Association
J. Maas J.R. Rath	Treaty 8 Tribal Association
I. Anderson	United Association of Plumbers and Pipefitters
D.G. Davies	Western Canada Producers Group (comprising AEC Marketing, Apache Canada Ltd., Anderson Exploration Ltd., Beau Canada Exploration Ltd., Benson Petroleum Ltd., Bonavista Petroleum Ltd., Cabre Exploration Ltd., Canadian Occidental Petroleum Ltd., Canor Energy Ltd., Chauvco Resources Ltd., Chevron Canada Resources, Conoco Canada Limited, Cordeca Corporation, Crestar Energy, Cypress Energy Inc., Encal Energy Ltd., Fortune Energy Inc., Genesis Exploration Ltd., Gulf Canada Resources Limited, Ironwood Petroleum Ltd., ISH Energy Ltd., Jarrod Oils Ltd., Merit Energy Ltd., Northstar Energy Corporation, Numac Energy Inc., Petro-Canada Oil and Gas, Pinnacle Resources Ltd., Poco Petroleums Ltd., Purcell Energy Ltd., Ranger Oil Limited, Remington Energy Ltd., Rigel Oil & Gas Ltd., Sabre Energy Ltd., Star Oil & Gas Ltd., Summit Resources Limited, Suncor Energy Inc., Talisman Energy Inc., Tarragon Oil & Gas Limited, Unocal Canada Ltd., and Wintershall Canada Ltd.)
G. Laplante	Aboriginal Pipelines
J.B. Ballem, Q.C. B. Stevenson	Alberta Natural Gas Company Ltd
H.R. Ward	Amoco Canada Petroleum Company Ltd.; Cochin Pipe Lines Ltd.
T.G. Kane, Q.C.	ANR Pipeline Company

E.C. Eddy	BC Gas Utility Ltd.
R.C. Beattie	CanWest Gas Supply Inc.
F.D. Cass	Consumers' Gas Company Ltd. (now Enbridge Consumers Gas)
C.B. Woods	Duke Energy Marketing Limited Partnership
R. McLennan G. McLennan C.B. Johnson R.M. Lonergan	Foothills Pipe Lines Ltd.; Foothills Pipe Lines (Alta.) Ltd.; Foothills Pipe Lines (Sask.) Ltd.; and Foothills Pipe Lines (South B.C.) Ltd.
W. Shalagan	Imperial Oil Resources
K.M. Fernandez	Mobil Oil Canada
D.I. Bloom	NICOR Inc.
G.J. Pratte K. Laroche	Northwestern Utilities Limited
F.R. Foran S. Lee D. Wright	NOVA Chemicals Ltd.
H.D. Williamson, Q.C. J. Liteplo J.H. Smellie	NOVA Gas Transmission Ltd.
D.M.K. Ellerton	Pacific Gas and Electric Company
E.S. Decter	Pan-Alberta Gas Ltd.
P. McCunn-Miller P. Kahler	PanCanadian Petroleum Limited
J.R.M. Kowch M.L. Voinorosky	ProGas Limited
M.J. Samuel	TransCanada Gas Services
P.R. Jeffrey J.M Murray R. Graw B. Andriachuk	TransCanada PipeLines Limited
J.M Murray R.W. Graw	TransVoyageur Transmission Ltd.

G. Cameron	Union Gas Limited
A.S. Hollingworth L.A. Cusano D.M. Wood	Viking Voyageur Gas Transmission Company, L.L.C.
L.G. Keough E. Bourgeault	Westcoast Energy Inc.
B.F. Kiely	Wisconsin Capacity Coalition (comprising Madison Gas and Electric Company, Wisconsin Fuel & Light Company, Wisconsin Gas Company, Wisconsin Public Service Corporation, and Northern States Power Company)
C.J.C. Page	Alberta Department of Energy
A. Johnstone	On His Own Behalf
R. Rutledge	On His Own Behalf
J.D. Carter, Q.C. T. King	Landowners of Grande Prairie County and Municipal District of Greenview (Byron Bue, Lowell Davis, Peter and Levke Eggers, Charles and Nora Evaskevich, Brian and Terry Fast, Raymond and Vicki Gilkyson, Stirling and Laura Hanson, Donald Meador, Mona Middleton, Brian and Janice Moe, Randy and Kris Moe, Franklin Moller, Lloyd and Katherine Olley, Scenic View Farms (Richard), Dale and Gwen Smith, Frank Thederahn, and Ed Welsh)
R. Bardak	On His Own Behalf
D. Bedier	On Her Own Behalf
Dr. W. Scott	On His Own Behalf
C. Bridge J. Austin C. Titus	Blueberry Farms Community
C.G. Apsassin	On His Own Behalf
R. Desfosses	On His Own Behalf
W. Sawchuk	Chetwynd Environmental Society
D.W. Orchard	Heartland Gas Initiative
B. Fayant	Métis Regional Council, Zone IV
G. Jones	Western Canada Wilderness Committee

J. Wachowich	Consumers Coalition of Alberta
D.E. Carlson L. Girvan	Strathcona County
T.R. Hankinson B.L. Hankinson	On Their Own Behalf
J. Rypien	Pipeline Contractors Association
M.W. Webber	Operating Engineers of Alberta
R. Collin	On His Own Behalf
S. Arcand	The Alexander First Nation
D.R. Horseman	Horse Lake First Nation
S. Elliott	On Her Own Behalf
J. Hanebury P. Noonan P. Enderwick	National Energy Board Counsel

Overview

(Note: This overview is provided solely for the convenience of the reader and does not constitute part of this Decision or the Reasons, to which the reader is referred for particulars. For the convenience of the reader, cross-references to the Reasons are provided.)

The National Energy Board, after taking into account extensive evidence compiled during 77 days of public hearings and the results of a comprehensive study on potential environmental effects, is satisfied that the proposed Alliance Pipeline Project is required by the public convenience and necessity. Therefore, subject to the approval of the Governor in Council, Alliance Pipeline Ltd. will receive a certificate from the Board authorizing the construction of the pipeline in Canada. The certificate will contain 54 terms and conditions to ensure that the Project is carried out with proper regard to the protection of property and the environment, the safety of the public, and other interests. The Board has also approved the tolling arrangement negotiated between Alliance and its shippers.

The following sections contain background on the application, the hearing process, and the key issues that were raised.

The Application [1.1]

On 3 July 1997, Alliance Pipeline Ltd. ("Alliance" or "the Company") applied to the National Energy Board ("Board") on behalf of the Alliance Pipeline Limited Partnership for (i) a certificate of public convenience and necessity to construct and operate the Canadian portion of a proposed natural gas pipeline system from northeastern British Columbia ("B.C.") and northwestern Alberta to the area of Chicago, Illinois and (ii) related toll and tariff authorizations. The application was made pursuant to Parts III and IV of the *National Energy Board Act* ("*NEB Act*").

The Canadian portion of the pipeline, referred to as the Alliance Pipeline Project ("Project"), is also subject to the provisions of the *Canadian Environmental Assessment Act* ("*CEAA*"). The *Comprehensive Study List Regulations*, made pursuant to the *CEAA*, required a comprehensive study of the proposal, since more than 75 km of new right-of-way will be required.

Alliance proposes to construct (i) approximately 1565 km (970 miles) of mainline and related facilities from a point near Gordondale, Alberta to a point on the Canada / United States border near Elmore, Saskatchewan and (ii) approximately 770 km (480 miles) of lateral pipelines and related facilities in B.C. and Alberta. Seven mainline compressor stations and 26 lateral compressor stations are planned. The mainline will be 914 and 1067 mm (36 and 42 inches) in diameter and the laterals will range in size from 114 to 610 mm (4 to 24 inches).

The pipeline is scheduled to be in service in the second half of the year 2000 and will be capable of delivering 37.5 million cubic metres (1.325 billion cubic feet) of natural gas per day on a firm basis. The estimated capital cost of the Canadian-based facilities is approximately $2 billion.

GH-3-97 Proceeding [1.2]

On 3 September 1997, the Board issued Hearing Order GH-3-97 setting out the Directions on Procedure for the public hearing to be conducted in respect of the Alliance Pipeline proposal.

The GH-3-97 proceeding was held both (i) to obtain the evidence and views of interested persons on the application which had been filed by Alliance under the *NEB Act* and (ii) to provide a forum for public participation in the comprehensive study to be conducted under the *CEAA*.

The hearing spanned 77 days between the dates of 6 January 1998 and 21 May 1998, with the Board's offices in Calgary serving as the primary hearing location. Regional hearings were held during the month of February 1998 in Regina, Fort St. John, and Edmonton to facilitate participation by persons living in areas along the proposed pipeline route.

On 7 April 1998, an "Agreement on Natural Gas Pipeline Regulation, Competition and Change to Promote a Competitive Environment and Greater Customer Choice" was signed by the Canadian Association of Petroleum Producers, NOVA Corporation, NOVA Gas Transmission Ltd. ("NGTL"), the Small Explorers and Producers Association of Canada, and TransCanada PipeLines Limited ("TCPL"). The signing of the document led NGTL and TCPL to withdraw substantial portions of evidence which they had filed in commercial opposition to Alliance.

Environmental Assessment [1.4]

The Board completed a Comprehensive Study Report ("CSR") for the Project in accordance with the provisions of the *CEAA* and also to satisfy its responsibilities pursuant to section 52 of the *NEB Act* relating to environmental matters. The CSR, which was publicly released on 2 October 1998, took into consideration comments from the public as well as advice from the other two Responsible Authorities for the Project (being Fisheries and Oceans Canada and the Prairie Farm Rehabilitation Administration), other federal departments, and the Province of Saskatchewan.

The Responsible Authorities (including the Board) concluded that the Project is not likely to cause significant adverse environmental effects, provided that the mitigative measures and undertakings committed to during the hearing are implemented together with the 41 recommendations contained in the CSR.

Having taken into consideration the CSR, public comments filed pursuant to subsection 22(2) of the *CEAA*, and the Canadian Environmental Assessment Agency's recommendation, the Minister of the Environment also concluded that the Project, as described, is not likely to cause significant adverse environmental effects. As a result, the Minister referred Alliance's proposed project back to the Board and other responsible authorities for action under subsection 37(1) of the *CEAA*.

The Board will include the 41 recommendations contained in the CSR as terms and conditions to any certificate issued to Alliance.

Economic Feasibility [1.3.1 and 2]

Consistent with past practice for natural gas pipeline facility proposals, the Board assessed the economic feasibility of the Project by determining the likelihood of the applied-for facilities being used at a reasonable level over their economic life and the likelihood of the demand charges being paid. [2.1]

This assessment included an evaluation of (i) the availability of long-term gas supply, (ii) the long-term outlook for gas markets, (iii) the contractual commitments underpinning the proposal, and (iv) project financing. The Board's main findings in these areas were as follows:

(i) *Supply* - The Board recognized that the approval and construction of the Project could result in pipeline capacity leading supply for a period of time and result in some temporary offloading from other pipeline systems. However, it is inherent in the nature of any greenfield pipeline that the investment must be large enough to take advantage of economies of scale. The Board found that Alliance made a credible case that, on a long-term basis, overall supply will be sufficient to sustain reasonable utilization rates of the Alliance Pipeline and of the other pipeline systems transporting gas from the Western Canada Sedimentary Basin. [2.2]

(ii) *Markets* - The Board is satisfied that natural gas markets will be sufficient to support the Alliance Pipeline over the life of the Project. Canadian gas producers have demonstrated that they can compete successfully in U.S. markets and the long-term outlook for gas demand in the U.S. appears to be robust. [2.3]

(iii) *Contractual Commitments* - The Board noted that subscriptions have been taken by 37 shippers for approximately 98 per cent of the available firm capacity for terms of 15 years, which translates into demand charge commitments of $4.7 billion (including the U.S. segment of the pipeline, the commitments are for $8.2 billion). The evidence satisfied the Board that shippers committed to the Project after a thorough assessment of the value of the proposed transportation service and the associated risks. [2.4]

(iv) *Financing* - The Board was satisfied with both the ability of Alliance and its partners to finance the Project and the proposed debt/equity structure. Alliance indicated that it had firm commitments for all of the equity, and that its lenders had underwritten all of the debt financing on a non-recourse basis. [2.4]

Having considered all of the evidence, the Board concluded that the Project is economically feasible. [2.5]

Potential Commercial Impacts [1.3.1 and 3]

A large-scale project such as that proposed by Alliance inevitably raises the potential for commercial impacts on persons other than the owners and users of the pipeline. The Board considered these potential impacts in its overall assessment of whether the applied-for Project is in the public convenience and necessity. Its main findings in this regard were as follows:

(i) *Competition and Netbacks* - The Board found that Alliance is a well-conceived project that will provide an innovative alternative to the existing gas transportation infrastructure. The Board concluded that, in the long term, the Alliance Pipeline will help ensure that there is adequate transportation capacity from the Western Canada Sedimentary Basin to the major market centres and that the pipeline will have a positive effect on producer netbacks. The Board also found that the long-term competitive benefits of the Project will be significant and will extend beyond those directly participating in the Project as owners and shippers. [3.1]

(ii) *Potential Impacts on Existing Pipeline Infrastructure* - The Board heard arguments relating to potential impacts on pipeline facilities owned by NGTL, Northwestern Utilities Limited, Foothills Pipe Lines Ltd., and BC Gas Utility Ltd. (the last by virtue of its dependency on the pipeline system of Westcoast Energy Inc.). These arguments focused mainly on the potential for offloading and stranded capacity. Having considered all of the evidence and the submissions of parties, the Board was not persuaded that there were sufficient public interest reasons to justify any regulatory action in the context of the Alliance application. The Board also noted that the potential for some duplication of facilities is inherent in the nature of competition, and that duplication which results in beneficial competition may be considered to be in the public interest. [3.2]

(iii) *Potential Impacts on the Alberta Petrochemical Industry* - The Board heard arguments relating to concerns that the removal of natural gas liquids from Alberta on the Alliance Pipeline would result in negative impacts on the Alberta petrochemical industry. The concerns focused on the following elements of Alliance's proposed tariff: (1) the requirement for shippers to relinquish the rights to liquids entrained in the gas streams delivered to Alliance; (2) the proposed volumetric tolling methodology; (3) Authorized Overrun Service, whereby firm service shippers may utilize spare capacity for the cost of fuel only; and (4) physical access to liquids on the Alliance Pipeline. Having considered all of the evidence and submissions by parties, the Board did not find that any features of Alliance's proposed transportation service package are contrary to the public interest. In the Board's view, the evidence showed that there will be adequate ethane supply for both the currently planned and future expansions of the Alberta petrochemical industry. Further, the Board does not believe that physical access to the liquids that will be carried on the Alliance Pipeline will be a significant issue once the pipeline is in operation. [3]

(iv) *Domestic Access to Natural Gas* - The Board was not persuaded to adopt any specific proposals advanced by parties aimed at enhancing domestic access to natural gas. The Board suggested, in its Reasons, that potential gas buyers should attempt to negotiate commercial arrangements with gas suppliers and gas transportation companies under market conditions. [3.4]

Socio-Economic and Land Matters [4]

As part of its public interest determination, the Board considered the potential socio-economic effects of the Project. The three principal categories studied by Alliance were: (i) employment, non-labour impacts, and income; (ii) municipal services; and (iii) quality of life. Certain issues, including those relating to quality of life, were addressed in the CSR. [4.1.1]

Alliance estimated that direct employment associated with construction would total 4,485 person-years, and that, in the broader context, construction would create approximately 12,000 person-years of direct, indirect, and induced employment in B.C., Alberta, and Saskatchewan. Alliance further submitted that operation and maintenance of the pipeline in Canada would generate approximately 335 person-years of direct, indirect, and induced employment. [4.1.2]

Alliance also described the mechanisms that will be used to ensure First Nations and Métis participation in the Project. The Board will include in any certificate a condition requiring Alliance to report on its performance in respect of its First Nations and Métis employment and commercial participation objectives for the construction and operation of the pipeline. [4.1.2]

The Board was satisfied with the information provided by Alliance on the potential adverse effects of the Project on municipal services. [4.1.3]

In respect of land matters, the Board considered Alliance's proposed land requirements for permanent right-of-way and temporary work space and found that these were reasonable and justified. The Board was also satisfied with the proposed general location of the Alliance Pipeline. The Board considered Alliance's request for an 800 m corridor but concluded that such a corridor would not be consistent with the specific route that was communicated to landowners and that the request was not supported by the studies undertaken for the Project. Any certificate issued will be conditioned to require Board approval of any deviations from the specific route. [4.2]

Engineering and Safety Matters [5]

The Project is planned to be designed, constructed, and operated in accordance with the Board's *Onshore Pipeline Regulations* and the latest edition of the CSA Z662 standard entitled *Oil and Gas Pipeline Systems* ("CSA Z662-96"). Alliance will also comply with other federal, provincial, and municipal codes and regulations where applicable. [5.1]

The pipeline will employ high-pressure technology and will be capable of transporting rich natural gas mixtures. The unique combination of pressure and gas composition will result in the transportation of dense phase gas and will give rise to cost efficiencies. State-of-the-art leak detection and in-line inspection techiques will be employed. [5.1]

Pursuant to section 108(5.1) of the *NEB Act*, the Board waived the requirement for Alliance to obtain leave to cross other utilities, aside from navigable waterways and railways, provided that (i) a written agreement is entered into between Alliance and the utility owner for the construction of any crossings and (ii) any such crossings are constructed in conformity with CSA Z662-96 requirements. Where agreement is not reached, the Board will adjudicate after hearing from both Alliance and the utility owner. [5.2]

The Board considered the various aspects of Alliance's fracture prevention and control design. The Board is satisfied with the Company's fracture initiation control design and notes that the fracture propagation control design is proposed to be validated through a full-scale burst testing program. Any certificate issued will include a condition requiring Alliance to file a detailed report on the burst test results with the Board for approval at least 30 days prior to the commencement of mainline trenching. The condition will further stipulate that, in the event that the tests are unsuccessful, Alliance shall submit operating limits or a crack arrestor program, with or without operating limits, for either or both of the 914 mm and 1067 mm diameter sections of mainline, together with technical justification, for approval by the Board. [5.3]

Traffic, Tolls, & Tariffs and Form of Regulation [1.3.2 and 6]

Alliance requested that the Board issue an order pursuant to Part IV of the *NEB Act* (i) approving the toll methodology and the tariff that would apply to the service provided by the Company and (ii) designating Alliance as a Group 2 company for purposes of toll and tariff regulation.

The Board has determined that (i) Alliance's proposed tolling methodology would result in tolls that are just and reasonable and (ii) that there would be no unjust discrimination in tolls, service, or facilities. The Board noted that the tariff and resultant tolls were negotiated between Alliance and its shippers, and considers that the proposed volumetric tolling methodology best respects the principle that tolls should be cost-based. The Board also found Alliance's proposed Authorized Overrun Service to be an innovative and appropriate approach to dealing with the variability of available capacity on a natural gas pipeline.

The Board concluded that Alliance should be designated as a Group 1 company for purposes of toll and tariff regulation, based on the following considerations: (i) the Alliance Pipeline will be one of the largest under the Board's jurisdiction, (ii) it will transport natural gas for a number of third party shippers, and (iii) the Company's tolls will be set on a cost-of-service basis. The Board also decided that it would be appropriate to relieve Alliance from the requirement to file Quarterly Surveillance Reports and Performance Measures.

Chapter 1

Introduction

1.1 The Application and Project Overview

On 3 July 1997, Alliance Pipeline Ltd. ("Alliance", "the Applicant", or "the Company") applied to the National Energy Board ("Board" or "NEB") on behalf of the Alliance Pipeline Limited Partnership for (i) a certificate of public convenience and necessity to construct and operate the Canadian portion of a proposed natural gas pipeline system from northeastern British Columbia ("B.C.") and northwestern Alberta to the midwest United States ("U.S." or "U.S.A.") and (ii) related toll and tariff authorizations.[1] The application was made pursuant to Parts III and IV of the *National Energy Board Act* ("*NEB Act*").

The Canadian portion of the pipeline system, referred to as the Alliance Pipeline Project ("Project"), is also subject to the provisions of the *Canadian Environmental Assessment Act* ("*CEAA*"). The *Comprehensive Study List Regulations*, made pursuant to the *CEAA*, required a comprehensive study of the proposal, since more than 75 km of new right-of-way would be required.

Alliance proposes to construct (i) approximately 1565 km (970 miles) of mainline and related facilities from a point near Gordondale, Alberta to a point on the Canada/U.S. border near Elmore, Saskatchewan and (ii) approximately 770 km (480 miles) of lateral pipelines and related facilities in B.C. and Alberta. Seven mainline compressor stations and 26 lateral compressor stations are planned. The mainline would be 914 and 1067 mm (36 and 42 inches) in diameter and the laterals would range in size from 114 to 610 mm (4 to 24 inches).

The U.S. portion of the pipeline would extend approximately 1430 km (890 miles) to the system's terminus near Chicago, Illinois, where it would connect with the integrated North American pipeline grid. Alliance Pipeline L.P. filed an application with the Federal Energy Regulatory Commission ("FERC") in Washington, D.C. for a certificate of public convenience and necessity to construct and operate the U.S.-based facilities.[2]

The Project is depicted in Figures 1-1, 1-2, and 1-3, and is described in more detail in Appendix I. As shown by the last of those figures, and the accompanying lateral legend (Table 1-1), the system is configured to receive gas from 44 existing gas plants.

The pipeline is proposed to commence service in the second half of the year 2000 and would be capable of delivering 37.5 million cubic metres (1.325 billion cubic feet) of natural gas per day on a

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[1] Alliance Pipeline Ltd. is the general partner of the Alliance Pipeline Limited Partnership, which has as its members (as of 30 January 1998): IPL Energy Inc., Westcoast Energy Inc., and Mapco Canada Energy Inc. together with affiliates of Fort Chicago Energy Partners L.P., Coastal Corporation, PanEnergy Corp., and Unocal Canada Limited.

[2] On 23 September 1998, Alliance Pipeline L.P. publicly announced that it had accepted a certificate of public convenience and necessity which was offered by the FERC on 17 September 1998.

firm basis. As further detailed in section 2.4, approximately 98 per cent of the available firm capacity has been subscribed for a 15-year term.

Figure 1-1
The Proposed Alliance Pipeline Project

Figure 1-2
Pipeline Route Map/Mainline and Compressor Stations

Figure 1-3
Pipeline Route Map/Laterals

Table 1-1
Lateral Pipeline Legend

Lateral Name	Plant No.	Plant Name	Plant Location
Highway Lateral	BC 01	Highway - WGSI	b-36-I 94-B-16
Aitken Creek Lateral	BC 02	Aitken Creek - Westcoast	d-44-L 94-A-13
Taylor Lateral	BC 03	McMahon - Westcoast	01-36-82-18W6
Taylor Lateral	BC 04	Younger - Solex	02-36-82-18W6
Boundary Lake Lateral	AB 05	Boundary - Petrocan	14-24-84-15W6
Boundary Lake Lateral	AB 07	Boundary Lake S. - Rigel	01-14-85-09W6
Peace River Lateral	AB 09	Fourth Creek - Cranrock	16-11-82-09W6
Peace River Lateral	AB 10	Josephine - Rigel	09-01-88-10W6
Pouce Coupe Lateral	AB 11	Pouce Coupe - Star	11-34-79-12W6
Gordondale West Lat.	AB 12	Pouce Coupe - C.N.R.L.	11-19-79-11W6
Gordondale West Lat.	AB 13	Gordondale - Westcoast	16-02-79-12W6
Peace River Lateral	AB 14	Gordondale - Cranrock	11-24-79-11W6
Whitburn Lateral	AB 15	Progress - Suncor	07-22-78-09W6
Whitburn Lateral	AB 16	Progress - Norcen	08-01-78-10W6
Valhalla North Lateral	AB 17	Valhalla - Can. Abraxas	13-21-76-09W6
Valhalla S. Connection	AB 20	Valhalla - Crestar	01-29-75-09W6
Teepee Creek Lateral	AB 21	Teepee Creek - Talisman	07-02-74-04W6
Spirit River Lateral	AB 23	Sexsmith - AEC	04-08-75-07W6
Hythe Lateral	AB 24	Hythe / Brainard - AEC	14-18-74-12W6
Hythe Lateral	AB 26	Knopic - Rigel	16-21-73-10W6
Wembley Connection	AB 27	Wembley - Crestar	05-19-73-10W6
Elmworth Lateral	AB 27A	Elmworth - Can. Hunter	01-08-70-11W6
Wapiti Lateral	AB 29	Wapiti - Imperial	04-08-69-08W6
Gold Creek Lateral	AB 30	Gold Creek - Petrocan	13-26-67-05W6
Karr Lateral	AB 31	Karr - Can. Hunter	04-10-85-02W6
Simonette Lateral	AB 32	Simonette - Encal	09-06-63-25W5
Ante Creek Lateral	AB 34	Ante Creek - Rio Alto	10-18-65-23W5
Ante Creek Lateral	AB 35	Waskahigan - Rio Alto	15-07-64-23W5
Bigstone Lateral	AB 36	Bigstone W. - Petromet	14-28-59-22W5
Bigstone Lateral	AB 37	Bigstone - Amoco	06-10-61-22W5
Two Creeks Lateral	AB 38	Two Creeks - Summit	07-04-63-18W5
Fox Creek Lateral	AB 40	Kaybob - Petrocan	08-09-64-19W5
Kaybob Lateral	AB 41	Kaybob - S. I & II - Amoco	01-12-62-20W5
Edson West Lateral	AB 43	Galloway - Ranger	14-14-53-20W5
Edson Lateral	AB 44	Edson - Talisman	04-11-53-18W5
Edson Lateralp	AB 44A	Wolf South - Poco	05-01-51-15W5
Kaybob South Lateral	AB 45	Kaybob S. - III Chevron	11-15-59-18W5
Edson Lateral	AB 46	W. Whitecourt - Amoco	08-17-60-15W5
Carson Creek Lateral	AB 47	Carson Creek - Mobil	04-23-61-12W5
Whitecourt Lateral	AB 48	Whitecourt - Petrocan	12-26-59-11W5
Paddle River Lateral	AB 49	Paddle River - Canoxy	13-06-57-08W5
Cherhill Lateral	AB 50	Cherhill - Chauvco	02-25-56-06W5
Fort Sask. Lateral	AB 53	Fort Sask. - Chevron	05-14-55-22W4
Fort Sask. Lateral	AB 54	Fort Sask. - Dow	12 & 13-55-22W4

The estimated capital cost of the entire pipeline to Chicago is approximately $3.7 billion in Canadian dollars, about $2 billion of which would be for the Canadian portion of the system.

For logistical purposes, Alliance has divided the construction of the mainline into nine segments or spreads to be built over 18 months. Lateral construction work would also be packaged into spreads. Individual contractors may construct several laterals.

1.2 GH-3-97 Proceeding

On 3 September 1997, the Board issued Hearing Order GH-3-97 setting out the Directions on Procedure for the public hearing to be conducted in respect of the Alliance Pipeline proposal. The list of issues that appeared in the hearing order has been reproduced as Appendix II.

As the Board indicated in its hearing order, the GH-3-97 proceeding was held both (i) to obtain the evidence and views of interested persons on the application which had been filed by Alliance under the *NEB Act* and (ii) to provide a forum for public participation in the comprehensive study to be conducted under the *CEAA*.

The Board convened a pre-hearing conference on 17 November 1997 (and which spanned six days) to hear argument on a number of pre-filed notices of motion. Among the outcomes were (i) Board directions to Alliance for additional evidence and (ii) the fixing of 6 January 1998 as the commencement date for the oral hearing.

The oral hearing spanned 77 days between the dates of 6 January 1998 and 21 May 1998, with the Board's offices in Calgary serving as the primary hearing location. Regional hearings were held during the month of February 1998 in Regina, Saskatchewan, Fort St. John, B.C., and Edmonton, Alberta to facilitate participation by persons living in areas along the proposed pipeline route.

On 7 April 1998, an "Agreement on Natural Gas Pipeline Regulation, Competition and Change to Promote a Competitive Environment and Greater Customer Choice" ("the Accord") was signed by the Canadian Association of Petroleum Producers ("CAPP"), NOVA Corporation, NOVA Gas Transmission Ltd. ("NGTL"), the Small Explorers and Producers Association of Canada ("SEPAC"), and TransCanada PipeLines Limited ("TCPL").

The Accord recognized the importance of maintaining an alignment of interest and embraced the following three guiding principles:

(i) support for competition and greater customer choice;

(ii) the need to construct competitive incremental pipeline capacity from the Western Canada Sedimentary Basin ("WCSB") by both new competitors and existing pipelines alike in a timely, safe, and cost-effective manner; and

(iii) the need to effect regulatory changes that would provide existing and new pipelines equal opportunity to compete, recognizing that such competition is desirable and in the best interests of all industry stakeholders.

The signing of the Accord led NGTL and TCPL to withdraw substantial portions of evidence which they had filed in commercial opposition to Alliance. For convenience of reference, the full text of the Accord has been reproduced as Appendix III.

1.3 Requested Authorizations and Statutory Tests

1.3.1 Certificate of Public Convenience and Necessity

The certificate application by Alliance was filed pursuant to section 52 of the *NEB Act*, which reads as follows:

> *The Board may, subject to the approval of the Governor in Council, issue a certificate in respect of a pipeline if the Board is satisfied that the pipeline is and will be required by the present and future public convenience and necessity and, in considering an application for a certificate, the Board shall have regard to all considerations that appear to it to be relevant, and may have regard to the following:*
> *(a) the availability of oil, gas or any other commodity to the pipeline;*
> *(b) the existence of markets, actual or potential;*
> *(c) the economic feasibility of the pipeline;*
> *(d) the financial responsibility and financial structure of the applicant, the methods of financing the pipeline and the extent to which Canadians will have an opportunity of participating in the financing, engineering and construction of the pipeline; and*
> *(e) any public interest that in the Board's opinion may be affected by the granting or refusing of the application.*

During final argument, comments were made by counsel for Westcoast Energy Inc. ("WEI") on the degree of latitude provided to the Board by the statute. In this connection, the Board notes that the English and French versions of section 52 convey different meanings. The English version states that the Board may have regard to the factors described in paragraphs (a) through (e), while the meaning of the French version does not convey that element of discretion and suggests that the factors in paragraphs (a) though (e) must be considered.[1] Since both versions are official, resort must be taken to the rules for construing bilingual legislation to determine the intention of Parliament. Applying the rules of statutory interpretation applicable in this context, the Board is of the opinion that the French version of section 52 conveys the intention of Parliament and is the version which must be applied.

In recent years, the Board has assessed the economic feasibility of a gas pipeline facilities application by determining the likelihood of the facilities being used at a reasonable level over their economic life

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[1] The French version of section 52 of the *NEB Act* reads as follows (more restrictive text underlined): *Sous réserve de l'agrément du gouverneur en counseil, l'Office peut, s'il est convaincu de son caractère d'utilité publique, tant pour le présent que pour le futur, délivrer un certificat à l'égard d'un pipeline; ce faisant, <u>il tient compte de tous les facteurs qu'il estime pertinents, et notamment de ce qui suit</u> :*

(a) l'approvisionnement du pipeline en pétrole, gaz ou autre produit;
(b) l'existence de marchés, réels ou potentiels;
(c) la faisabilité économique du pipeline;
(d) la responsabilité et la structure financières du demandeur et les méthodes de financement du pipeline ainsi que la mesure dans laquelle les Canadiens auront la possibilité de participer au financement, à l'ingénierie ainsi qu'à la construction du pipeline;
(e) les conséquences sur l'intérêt public que peut, à son avis, avoir sa décision.

and the likelihood of the demand charges being paid.[1] This assessment typically includes an evaluation of such factors as (i) the availability of long-term gas supply, (ii) the long-term outlook for gas demand in the markets to be served, (iii) the contractual commitments underpinning the proposal, and (iv) project financing. Therefore, the subject of economic feasibility encompasses paragraphs (a) through (d) of section 52 of the *NEB Act*.

A large-scale project such as that proposed by Alliance inevitably raises the potential for commercial impacts on persons other than the owners and users of the pipeline. Paragraph 52(e) of the *NEB Act* enables the Board to consider these potential impacts in its overall assessment of whether the applied-for Project is in the public convenience and necessity. Other aspects considered under this paragraph include environmental protection, socio-economic impacts, and public safety.

The Board has generally aligned these Reasons with section 52 of the *NEB Act*. Chapter 2 addresses the economic feasibility of the Project while Chapters 3 through 5 address the other public interest considerations articulated above with the exception of environmental protection. As further detailed in section 1.4, that aspect was addressed in the Comprehensive Study Report ("CSR") for the Alliance Pipeline Project which was publicly released on 2 October 1998.

1.3.2 Traffic, Tolls, & Tariffs and Method of Regulation

Alliance requested that the Board issue an order pursuant to Part IV of the *NEB Act* (i) approving the toll methodology and the tariff that would apply to service provided by the Company and (ii) designating Alliance as a Group 2 company for purposes of toll and tariff regulation.

With respect to the former, the Board has a duty under Part IV to ensure that the tolls for the pipelines under its jurisdiction are just and reasonable, and that there is no unjust discrimination in tolls, service, or facilities.[2] The Board also has to establish an appropriate level of regulatory scrutiny and filing requirements in this area. For this purpose, the Board classifies each of the pipeline companies under its jurisdiction as either a Group 1 or Group 2 company. Matters pertaining to Part IV of the *NEB Act* are addressed in Chapter 6.

The Board notes that some aspects of Alliance's proposed transportation service package are relevant to the public interest determination that the Board must make pursuant to section 52 of the *NEB Act*, as they potentially have implications for parties other than Alliance and its shippers. These potential implications are addressed in Chapter 3.

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[1] The Board first articulated this test in its GH-5-89 decision respecting a TCPL expansion proposal (reference GH-5-89 Reasons for Decision, Volume 1 "Tolling and Economic Feasibility" dated November 1990, Chapter 3, pages 26 and 29).

[2] Section 62 of the *NEB Act* states as follows: *All tolls shall be just and reasonable, and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate.* Section 67 states that: *A company shall not make any unjust discrimination in tolls, service or facilities against any person or locality.*

1.4 Environmental Assessment

The Board completed a CSR for the Alliance Pipeline Project in order to satisfy the requirements of the *CEAA* and also to satisfy its responsibilities pursuant to section 52 of the *NEB Act* relating to environmental matters. The CSR took into consideration comments from the public as well as advice from the other Responsible Authorities, interested federal departments (including Environment Canada), and the Province of Saskatchewan. The other two Responsible Authorities for the Alliance Pipeline Project were Fisheries and Oceans Canada and the Prairie Farm Rehabilitation Administration.

The CSR described the Project, the environmental assessment process (including public participation), the potential environmental effects, the assessment methodology, mitigative measures, and the criteria used in evaluating the significance of the environmental effects. It also provided conclusions and recommendations regarding the significance of the Project's potential adverse environmental effects.

The Responsible Authorities (including the NEB) concluded that the Project is not likely to cause significant adverse environmental effects, provided that the mitigative measures and undertakings committed to by Alliance during the hearing are implemented together with the 41 recommendations contained in the CSR.

As previously indicated, the Board used its public hearing process as a means of obtaining the views of interested persons on both the particulars of the environmental assessment and Alliance's application under the *NEB Act* for a certificate of public convenience and necessity to construct and operate the pipeline. Prior to the public hearing, the environmental assessment process commenced with a public scoping process to identify the scope of the assessment including the factors to be assessed. After the public hearing, participants were provided with an opportunity to comment on a draft of the CSR prior to it being finalized.

The Canadian Environmental Assessment Agency ("Agency") facilitated a public comment process on the final CSR between 5 October 1998 and 3 November 1998. Following the receipt of comments, the CSR was forwarded to the Minister of Environment for a decision on the course of action to be taken under section 23 of the *CEAA* in respect of the environmental assessment of the Project. The Board's decision on Alliance's certificate application was reserved pending this determination.

Having taken into consideration the CSR, public comments filed pursuant to subsection 22(2) of the *CEAA*, and the Agency's recommendation, the Minister of the Environment concluded that the Project, as described, is not likely to cause significant adverse environmental effects. As a result, the Minister of the Environment referred Alliance's proposed project back to the Board and other Responsible Authorities for action under subsection 37(1) of the *CEAA*.[1]

Views of the Board

Upon receipt of the referral from the Minister of the Environment, the Board has considered the CSR and is of the view that, with the implementation of Alliance's proposed mitigative measures and the recommendations set forth in the CSR, the Project is not likely to cause significant adverse environmental effects. In this regard,

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[1] Reference Appendix IV for a copy of the Minister's correspondence to the Board dated 23 November 1998.

the Board would incorporate all recommended conditions as described in the CSR into any certificate issued to Alliance for the Project (see Appendix V). [1]

The seven recommendations contained in Chapter 5 of the CSR (and which appear in Appendix V of these Reasons as certificate conditions 18, 33, 43, and 50 through 53) describe the procedures that would be put in place to inspect, monitor, and follow up on environmental issues relevant to the Project should a certificate be issued. It should be noted that the Board will carry out its own inspections and audits in accordance with the relevant legislation and conditions of approval to ensure protection of the environment.

Chapter 3 of the CSR provides a description of Alliance's public participation program. The Board is of the view that the requirements of Part II of the Board's *Guidelines for Filing Requirements* have been satisfied as interested groups and persons have been afforded opportunities for meaningful public input at both the local and regional levels during the planning and design stages of the Project.

Alliance stated that it would continue to apprise the Board of the results of ongoing consultation on a quarterly basis until such time that all concerns and comments are resolved. Alliance also noted that it would notify the Board of any new issues that may arise as a result of consultations. With respect to specific issues, such as the development of Alliance's air quality monitoring programs, the issue of further consultation is addressed in the recommendations contained in the CSR and the corresponding conditions in Appendix V of these Reasons.

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[1] Reference the table at the end of Appendix V for concordance between the recommendations contained in the CSR and the certificate terms and conditions.

Chapter 2

Economic Feasibility

Some parties, notably TCPL and Foothills Pipe Lines Ltd. ("Foothills"), invited the Board to clarify its expectations with respect to the standards an applicant is expected to meet to demonstrate that pipeline facilities applied for under section 52 of the *NEB Act* are economically feasible. This chapter first addresses the arguments of parties with respect to the appropriate test of economic feasibility and then addresses the arguments with respect to supply, markets, and shipper commitments and project financing. It concludes with a finding on the economic feasibility of the applied-for facilities.

2.1 The Appropriate Test of Economic Feasibility

Views of the Applicant

Alliance stated that the Board should make a determination of the economic feasibility of the proposed pipeline facilities by having regard to evidence on all relevant factors which impact on the likelihood of the facilities being used at a reasonable level over the Project's economic life and the likelihood of the demand charges being paid.

Alliance maintained that there has been an evolution of the economic feasibility test over time. This evolution is part of the challenge to the traditional regulatory paradigm under which monopoly pipelines are regulated. It is part of the changing market dynamics, the increase in competition, and the deregulation of natural gas markets and prices.

In Alliance's view, the best evidence with respect to an assessment of the feasibility of the Project is provided by the financial commitments made to the Project. If markets work, and competition is present, evidence with respect to contracts and financial commitments should be adequate to demonstrate that the facilities will be used and paid for over the useful economic life of the Project; i.e. that the Project is economically feasible.

Views of Intervenors

TCPL took the view that, if the Alliance Project were to be certificated, the Board would be applying a relaxed standard for the determination of economic feasibility. TCPL contended that the determination of whether demand charges would be paid is difficult for the Board to make because Alliance's total capital cost is unknown. Therefore, TCPL argued that the toll or demand charge is indeterminate. TCPL maintained that the Board would either be dispensing with a determination as to whether the toll is likely to be paid over the economic life of the facilities or that it would be assuming that Alliance's shippers would pay regardless, and that would be the new standard.

According to TCPL, a second area in which an approval of the Alliance Project by the Board would represent a change in regulatory standards would be with respect to the advance capacity nature of the application. By approving the Alliance application, the Board would be moving further away from a need to demonstrate project-specific supply or market evidence. TCPL requested that the Board expressly state how it regards these and any other aspects in which it is adjusting the regulatory standard.

At the end of the hearing, TCPL stated that, on the strength of the Accord and the platform for industry consensus on regulatory change that the Accord represents, it did not oppose many of the changes to the regulatory standards of review that would be represented by certification of the Project. Rather, TCPL expected to receive similar treatment in the future.

Foothills argued that, in this new era of pipeline competition, all pipelines regulated by the Board must be subject to the same type and degree of regulation. For there to be fair competition, the Board must ensure that owners of existing pipelines are not encumbered by regulatory rules or precedents which inhibit competition.

Foothills stated that one important element of competition among pipelines is competition for commitment to capacity on new pipeline facilities. Ideally, the Board should have enunciated its rules or guidelines for the new era of competition before considering the Alliance Project.

Foothills recommended that the Board clarify the test for public convenience and necessity that should apply to all natural gas pipeline proposals, not just the Alliance Project, and that recognition should be given to the fact that the new era of pipeline competition will require a reduced level of economic regulation.

IPL Energy Inc. ("IPLE") submitted that consistent and fair regulatory treatment did not mean identical treatment or adhering to a set pattern that had been evident in past practice; rather, it meant considering the circumstances of each case on its own merits. If other pipeline companies wish to seek a change from the Board regarding their regulation following the Alliance hearing, they may do so.

In the view of Westcoast Energy Inc. ("WEI"), the Board has shown considerable flexibility in the administration of the economic feasibility test and has approached applications on a case-by-case basis. WEI submitted that the Board can continue to rely on the underlying fundamentals of the economic feasibility test.

Views of the Board

Since the GH-5-89 TCPL hearing, the Board has assessed the economic feasibility of applications for new natural gas pipeline facilities by determining the likelihood of the facilities being used at a reasonable level over the economic life of the project and the likelihood of the demand charges being paid. As noted in Chapter 1, this assessment includes an evaluation of: (i) the availability of long-term gas supply, (ii) the long-term outlook for gas markets, (iii) the contractual commitments underpinning the proposal, and (iv) project financing.

The Board is not changing its basic test of economic feasibility in the assessment of the Alliance Project. The Board notes, however, that there are important distinctions between the circumstances of the GH-5-89 application and the Alliance application. In GH-5-89, TCPL was proposing a large expansion to its system which would result in a large increase to its rate base. There was considerable concern express by existing shippers who believed they could be negatively impacted. They were concerned about the toll increase they would have to bear to help pay for the new facilities and about the risk that they might have to pay for the costs of any underutilization of the TCPL system in the event that the markets to be served by the expansion were not sustainable.

In its application, Alliance declared itself to be "at-risk" with respect to any underutilization of the applied-for facilities. If any of the shippers default on their demand charge payments, Alliance shareholders will bear any subsequent cost impacts, rather than other shippers on the system. This fact addresses one potentially significant public interest consideration. When there is potential for existing shippers to be harmed by a planned expansion, the Board has a heightened responsibility to ensure that the proposed expansion facilities are likely to be needed.

The Board is of the view that, in the circumstances of this application, considerable weight should be placed on an assessment of shipper support for the Project as demonstrated through a willingness to pay demand charges and a demonstration of the financing capability of the Project owners. Financial commitments made to the Project by shippers and banks, and the commercial judgements that stand behind these commitments, provide strong evidence of the commercial need for the Project. Further, the Board is of the view that the at-risk nature of the Project is a factor to be taken into account in the review of supply and market evidence.

With respect to the requests for clarification of regulatory "standards" that applications pursuant to section 52 of the *NEB Act* must meet, the Board reiterates that it is not making any fundamental changes to the test of economic feasibility. The Board is assessing the likelihood that the applied-for facilities will be used at a reasonable level over the economic life of the Project and the likelihood that the demand charges will be paid.

2.2 Gas Supply

At the outset of the hearing, Alliance argued that an overall supply study provided sufficient evidence with respect to the availability of gas to the Project. In support of its application, Alliance submitted an aggregate supply study prepared by Gilbert Laustsen Jung Associates Ltd. ("GLJ"). Following the hearing of procedural motions in November 1997, Alliance was required to submit supply information for each of its shippers. Nonetheless, Alliance argued that evidence on aggregate supply, in conjunction with transportation contracts, should be sufficient to support its application. Alliance maintained that shipper commitments behind the transportation contracts provide the best evidence that supply will be available and argued that shipper-specific supply evidence has very real limitations in today's natural gas market.

2.2.1 Overall Gas Supply

Views of the Applicant

The GLJ Study submitted by Alliance was based on an assessment of supply in the entire WCSB. It was Alliance's view that the study reflects the reality that all WCSB gas supply will be available to

Alliance, either directly or indirectly. Alliance stated that swaps and exchanges between producers would allow this to happen. Furthermore, the signing of the Accord has increased the likelihood that interconnections with NGTL will be built in the future, thus decreasing the need for exchanges.

The GLJ Study tested the adequacy of gas supply in the WCSB to meet overall demand under several demand scenarios. Two estimates of reserves were employed: (i) a Base Case that used a current Board estimate of ultimate reserves (7.9 $10^9 m^3$ or 280.2 Tcf) and (ii) a Sensitivity Case that used the current Board estimate plus an assumed growth in ultimate reserves of 2.5 per cent per year to the year 2007 (10.7 $10^9 m^3$ or 378.7 Tcf).

The GLJ Study concluded that only a small fraction of the currently-recognized resource base would need to be depleted to satisfy all demand over the next 20 years, even assuming large export pipeline capacity additions, combined with continuous robust growth in domestic gas demand. In addition, drilling activity levels that are reasonable, vis-a-vis recent industry performance, should maintain sufficient production capability to meet even the most aggressive demand scenario. Alliance claimed that the GLJ Study reflects defensible and reasonable production decline rates that are supported by previous studies by both Sproule Associates Limited ("Sproule") and the Board, and that its assumption of an average of 42.5 $10^6 m^3$ (1.5 Bcf) reserves additions per well is conservative.

In support of its claim, Alliance prepared summary tables of some of the key variables and assumptions behind the overall supply studies referred to during the proceeding. Highlights of these summaries are provided in Table 2-1.

In summary, Alliance argued that there would be adequate gas supplies available for both its Project and for existing pipeline systems.

Views of Intervenors

The Western Canada Producers Group ("WCPG"), IPLE, Union Gas Limited ("Union Gas"), and WEI all supported Alliance's view that the capacity of the WCSB was sufficiently robust to ensure that the Alliance pipeline would be used at reasonable levels over its economic life. Union added that it was confident that the market forces that have driven the Alliance Project will operate to keep both existing systems and Alliance substantially full for the foreseeable future. WEI argued that there was no basis to suggest that anything other than a normal refill period would occur following start-up of Alliance and was confident that tools such as swaps and exchanges would ensure that the necessary supply would be available to Alliance. Further, WEI believed that the Interconnection Policy in the Accord would alleviate the need for swaps and exchanges. [1]

Certain other intervenors were not supportive of Alliance's position.

The Green Alternatives Institute of Alberta ("GAIA") did not agree that Alliance's supply evidence demonstrated adequacy of supply and suggested that the GLJ study contained errors that neutralized its value. In particular, GAIA was of the view that the GLJ model added reserves beyond the level of ultimate potential assumed. Alliance argued that this was an incorrect conclusion. GAIA also argued that, because no new ultimate potential estimates had been published by either the Geological Survey

[1] The Interconnection Policy is set out in article 2 of the Accord (reference Appendix III).

of Canada or the Board since 1992 and 1994 respectively, it was unlikely that future ultimate potential estimates would grow significantly. GAIA was also concerned that the number of new wells required would be significantly higher than estimated by Alliance.

Table 2-1
Summary of Overall Supply Evidence

Study	Ultimate Potential $10^{12}m^3$ (Tcf)	Maximum Annual Production from WCSB 10^9m^3 (Tcf)
Coles Gilbert Associates Ltd. 1994 study prepared for Foothills in support of its Wild Horse Pipeline Project	8.5 (300) from WCSB	170 (6.0) in 2011
Sproule Associates Limited July 1996 study prepared for Foothills in support of its 1998 Eastern Leg Expansion Project	8.1 (287) from Alberta 9.9 (351) from WCSB	184 (6.5) in 2012 (WCSB Case A)
Sproule Associates Limited May 1997 study prepared for TCPL in support of its GH-2-97 facilities application	7.7 (270) from Alberta 9.3 (329) from WCSB	212 (7.5) in 2017 (Base Case)
NGTL May 1997 Annual Plan	>6.0 (>210) from Alberta	
Gilbert Laustsen Jung Associates Ltd. prepared for Alliance	Base Case (NEB Estimates) 5.6 (196) from Alberta 7.4 (260) from WCSB (conv.) 7.9 (280) from WCSB (total) Current NEB plus 2.5% Growth 7.7 (270) from Alberta 10.2 (359) from WCSB (conv.) 10.7 (379) from WCSB (total)	204 (7.2) in 2019 204 (7.2) in 2019

Foothills argued that the overall supply evidence was nothing more than a literature search and a trend analysis with some judgement applied. Foothills suggested that the Sproule Study which was undertaken for its 1998 Eastern Leg Expansion Project implied that adding an additional 46.7 $10^6m^3/d$ (1.65 Bcf/d) for Alliance would result in insufficient production capacity for existing pipelines and Alliance by 2003. Foothills was concerned that there was a potential lack of deliverability that would result in shippers having to compete for supplies that would otherwise be transported on existing pipeline systems. Alliance countered that, when properly applied, the Sproule model supports the Alliance case.

NGTL was concerned that there may not be sufficient supply to fully satisfy the needs of both Alliance and NGTL. It retained Fekete Associates Inc. ("Fekete") to examine the supply available at the 35 receipt points that would be common to both NGTL and Alliance (depicted in Figure 2-1). NGTL argued that the Fekete Study of the Alliance catchment area represented the only receipt-specific supply information filed during the proceeding. The Fekete analysis was based on a production decline method and predicts an 18-year refill (i.e. either Alliance, NGTL, or both pipelines would be underutilized for at least 18 years following the in-service date of the Alliance Pipeline). Based on its system design forecast, NGTL predicted a minimum 6-year refill period, but stated that the design forecast was not necessarily the appropriate forecast to use to determine a refill period.

Alliance argued that the Fekete evidence was not used by NGTL for either its Annual Plan or its facilities filings with the Alberta Energy and Utilities Board ("EUB") and that Fekete's reserves estimates were inconsistent with NGTL and EUB data. Accordingly, it contended that the evidence provided by this study was of no value to the Board. Alliance believed that, given a realistic assumption about Alliance's volume, decline rates, and additional wells, the refill period could be eliminated.

While Alliance suggested that NGTL's own forecasts demonstrate growth of supply availability at the 35 common receipt points, NGTL believed that all of the incremental volumes projected would be transported to market on NGTL during the period between 1997-98 and the Alliance in-service date. Alliance argued that there would still be incremental volumes available after its proposed in-service date.

The Rocky Mountain Ecosystem Coalition ("RMEC") submitted a study, prepared by Drummond Consulting, on discovered reserves, cumulative production, and remaining reserves for the area accessible to Alliance. That study reported an estimate of ultimate remaining gas reserves of 984.2 10^9m^3 (34.9 Tcf) in the immediate area and 1715.7 10^9m^3 (60.8 Tcf) in an expanded area which included gas reserves that might be available to Alliance at some point in the future.

BC Gas Utility Ltd. ("BC Gas") noted that, while Alliance had made a general statement that 25 to 40 per cent of its supply might come from B.C., it had designed its facilities into B.C. to remove some 14.2 10^6m^3/d (500 MMcf/d) or 25 per cent of the province's current gas production. BC Gas submitted that, at this rate, there would be a real risk of insufficient deliverability in B.C. over the short run.

2.2.2 Shipper-Specific Gas Supply

As indicated at the commencement of section 2.2, Alliance filed shipper-specific supply evidence. Detailed supply and demand information was provided for the 30 producer and aggregator shippers, representing about 60 per cent of the contracted capacity. The majority of the supply estimates submitted were those of either provincial regulators or third party consultants. All but four of the shippers currently have established reserves exceeding their total requirements over the term of their Alliance commitment. For each of the seven other shippers, which are either major gas marketing companies or Canadian local distribution companies ("LDCs"), Alliance provided a general description of overall marketing strategy.

Figure 2-1
Common NGTL/Alliance Receipt Points

Alliance argued that the level of supply detail for the aggregator and producer shippers was far greater than that provided by other pipeline companies in support of recent facility applications. Alliance also commented that much of the shipper supply information submitted was identical to that provided in support of recent export applications before the Board. Alliance argued that the shipper-specific supply information provides additional compelling evidence in support of its application.

Views of Intervenors

Several intervenors, namely the WCPG, Consumers' Gas Company Ltd. ("Consumers' Gas"), Duke Energy Marketing Limited Partnership ("Duke"), IPLE, ProGas Limited ("ProGas"), Union Gas, and WEI, supported Alliance's position regarding the relative value of its shipper supply information.

Consumers' Gas pointed out to the Board that the company does not match specific gas supply contracts with the terms of any specific transportation contracts. Consumers' Gas has adopted a gas acquisition process that provides flexibility to contract gas supply shortly before it is needed so as to obtain pricing and other terms to better match the gas market.

Duke argued that the shipper-specific supply issue advanced by Alliance's competitors should not distract the Board from an unconditional approval of the Alliance application.

IPLE pointed out that, for oil pipeline facility applications, the Board does not review project-specific or shipper-specific supply; rather, the focus is on macro supply. IPLE argued that the Board should also rely on an aggregate assessment of supply for the Alliance application. Evidence on shipper-specific supply does not provide assurance that gas will flow through the pipeline facilities over the lifespan of a project.

ProGas indicated that its gas supply is more than sufficient to meet all of its sales commitments, including sales intended to flow on Alliance. ProGas noted that it has access to 11.9 $10^6 m^3/d$ (419 MMcf/d) at the 44 proposed Alliance receipt points and has full supply capability through 2007 without the need for infill drilling or additional field compression.

Union Gas pointed out that for the past nine years, TCPL has benefitted from the Board's GHW-3-89 decision which exempted TCPL from filing shipper-specific supply information for normal growth markets.[1] It stated that, in the current market, neither buyers nor sellers of natural gas prefer long-term contracts. Union Gas argued that the Board gets assurance that Alliance will be used and useful through a combination of the dynamic market for gas and shippers' incentives to make maximum use of their transportation entitlements for which they are paying demand charges.

WEI argued that, in the current circumstances, there was no need for shippers to specifically dedicate supply in advance for the Board to have the necessary level of comfort to approve facilities. WEI indicated that Engage Energy, its marketing affiliate with sales in excess of 198 $10^6 m^3/d$ (7.0 Bcf/d), would be ensuring that WEI utilizes its contracted capacity at high levels throughout the term of its Transportation Service Agreement with Alliance.

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[1] NEB Reasons for Decision dated January 1990 on "Information on Gas Supply Required to be Provided by TransCanada PipeLines Limited in Support of its 1991/92 and 1992/93 Facilities Application" (GHW-3-89).

Both the RMEC and Foothills had concerns about the adequacy of shipper-specific supply supporting Alliance's proposed facilities. The RMEC pointed out that most of the Alliance shippers had far less than 15 years of supply and, therefore, there was "no demonstration" that there would be adequate gas supply to justify the Project.

Foothills was concerned that shippers which had no gas supply arrangements in place, and which had contracted for approximately 36 per cent of the Alliance Pipeline's capacity, would be competing for gas supply that would otherwise be transported on existing systems.

Views of the Board

The Board is required by section 52 of the *NEB Act* to have regard to the availability of gas to a proposed gas pipeline project. This requirement does not mean that the Board must assure itself that there will be adequate gas supplies to keep a pipeline project full at all times. Rather, the Board must be satisfied that there is a reasonable expectation that adequate supplies of natural gas will be available so that the facilities can be justified over the economic life of a project.

There was considerable discussion during the hearing about the usefulness of evidence on shipper-specific supply to the Board in making its determination on the adequacy of supply. The Board is of the view that, in the context of this application, the most appropriate way to satisfy itself with respect to the adequacy of supply is to examine the overall assessment of supply and the shipper commitments that underpin the transportation contracts.

The Board is of the view that it is unnecessary to rely on evidence that Alliance's shippers have long-term sources of supply in place at the outset of the Project. Adherence to this requirement would be inconsistent with current market realities and could impose unnecessary costs on Canadian producers. The natural gas market is extremely competitive and both producers and buyers strive to minimize costs in all aspects of their business. Producers now attempt to bring on additional supply capability as required by market demand, rather than developing this capability in advance.

The Board is also of the view that the financial commitments that shippers have made to pay $8.2 billion in demand charges on the Alliance system over the first 15 years of operation provides a powerful incentive for shippers to acquire adequate gas supplies. These companies, backed by their lenders, have made expert determinations that they will have access to adequate gas supplies in order to utilize their capacity entitlements on the Alliance Project.

The Board notes that the Alliance Project is unique in that it appears to be relying on a specific catchment area for gas supply to support the pipeline. NGTL's evidence, prepared by Fekete, was the only evidence subjected to cross-examination that directionally addressed supply from the Alliance catchment area. The Board has difficulty in accepting the results of the Fekete study because of its conservative approach and the study's relatively low estimates of supply availability from B.C. Further, the Board notes that NGTL's own forecasts suggest that field deliverability at the 35 receipt points which are common to NGTL and Alliance in Alberta will increase significantly.

In the absence of interconnections with NGTL, Alliance's 44 receipt points will provide the only physical connections through which gas supply can enter Alliance. The Board notes that the Accord provides for a framework which is intended to facilitate the construction of interconnections between Alliance and NGTL. Any such interconnections would provide Alliance with access to a broader area of supply. However, whether or not this occurs, the Board is of the view that the transportation contracts provide strong evidence that adequate supply will be available to the Alliance Pipeline.

The RMEC did not present a witness to support the evidence of Drummond Consulting that was tendered in evidence. The Board thereupon indicated to the RMEC that its failure to present a witness to speak to that evidence could tell against the RMEC in the weight to be attributed to it, a position which the RMEC freely acknowledged "would be a logical position that the Board may want to take".

The Board considers that this evidence should not be given great weight since it was in the nature of expert evidence and no expert witness appeared at the hearing to speak to it. To the extent that this evidence has been taken into account, however, the Board does not believe that it impeaches the evidence put forward by Alliance regarding the availability of supply to the pipeline.

With respect to overall supply, the Alliance Project, together with approved expansions to other pipeline systems, would provide an opportunity to increase natural gas production in the WCSB from 161 $10^9 m^3$ (5.7 Tcf) per year to nearly 190 $10^9 m^3$ (6.7 Tcf) per year. Alliance alone would provide 14.2 $10^9 m^3$ (0.5 Tcf) per year of additional capacity. The Board finds merit in Foothills' suggestion that this will create competition among pipelines for supply to an extent that has not previously existed, at least initially.

As illustrated by Table 2-1, the Board is mindful that projections of overall supply are inherently uncertain. The actual supply that is made available to the market will depend upon producers' decisions to develop supplies in the light of prevailing market conditions. However, on the basis of evidence filed by experts on basin potential, the Board is of the view that it is reasonable to expect that production from the WCSB can be increased to the projected levels.

The GLJ Study and the most recent Sproule Study (1997) both conclude that the WCSB can sustain production levels in excess of 198 $10^9 m^3$ (7 Tcf) per year. In the GLJ base case, production increases can match growing demand until 2011, at which time rates of 227 $10^9 m^3$ (8 Tcf) per year would be achieved. In GLJ's sensitivity case, production matches growing demand throughout the study period (1997-2019) reaching 241 $10^9 m^3$ (8.5 Tcf) per year at the end of that period. The GLJ approach is a somewhat simplified analysis of the ability of the WCSB to meet projected demand. Nonetheless, the analysis in GLJ's base case is based on sound and reasonable assumptions about ultimate potential, drilling activity, reserves to production ratios, decline rates, initial well productivities, and reserves per well. While the Board agrees that estimates of ultimate potential may increase in the future, it believes that the assumption by GLJ in its sensitivity case that ultimate potential will grow at a rate of 2.5 per cent a year appears optimistic. Furthermore, this assumption was not supported by any substantial analysis or evidence.

The Sproule Study is somewhat more detailed than the GLJ Study, including, for example, consideration of several financial parameters. However, like the GLJ Study, it utilizes a non-equilibrium model in which gas demand and price are externally generated. The modelling results indicate an ability to produce in excess of 198 $10^9 m^3$ (7 Tcf) per year throughout the period examined (1996-2018).

In summary, the Board recognizes that the approval and construction of the Alliance Pipeline Project could result in pipeline capacity leading supply for a period of time. The "lumpiness" of investment in a project such as this, along with the related shipper commitments to Alliance, may result in some temporary offloading from other pipeline systems, necessitating some period of refill. However, it is inherent in the nature of any greenfield pipeline that the investment must be large enough to take advantage of economies of scale. The Board accepts that Alliance has made a credible case that, on a long-term basis, overall supply will be sufficient to sustain reasonable utilization rates of the Alliance Pipeline and of other pipeline systems transporting natural gas from the WCSB.

2.3 Markets

Views of the Applicant

Alliance stated that the main objective of its Project is to provide incremental capacity from the WCSB to the U.S. market centre in the Chicago area and to other connected markets. Alliance argued that there is demand for incremental Canadian gas supplies and that there is a need for its Project to provide additional export capacity from the WCSB.

In support of its application, Alliance provided a market study prepared by the Reed Consulting Group ("Reed"). The Reed Study focused on the Chicago area and markets accessible from that market centre. The Alliance Project is intended to interconnect with three major pipelines: ANR Pipeline Company ("ANR"), Midwestern Gas Transmission Company, and Natural Gas Pipeline Company of America. Alliance indicated that there is approximately 123.2 $10^6 m^3/d$ (4,350 MMcf/d) of take-away capacity from the Chicago Hub, including two major LDCs (Peoples Gas and Light and Northern Illinois Gas Company). The physical capacity on the connecting interstate pipelines was not provided. The Reed Study also noted that there are a number of proposals to construct new pipeline connections that would move gas from the Chicago market centre to markets in the U.S. Northeast and Atlantic Seaboard regions.

Reed developed its market assessment by using published projections of gas demand prepared by the Gas Research Institute ("GRI"), the U.S. Energy Information Administration ("EIA"), the American Gas Association ("AGA"), and Natural Resources Canada. The study examined natural gas demand forecasts published in for all regions that Alliance considered to be accessible to its Project for the 1995 to 2015 period. The study incorporated most census regions in the U.S., including the South

Atlantic and Gulf Coast regions, although it excluded the Mountain and Pacific market regions. Table 2-2 summarizes the demand forecasts for those market regions accessible to the Alliance Project.

Table 2-2
U.S. Market Demand Forecast (Reed Study)
10^9m^3 (Tcf)

Year	Minimum	Average	Maximum
1995 Base Demand	329.4 (11.62)	438.7 (15.48)	514.3 (18.15)
2000 Forecast Demand Annual Growth Rate	495.9 (17.50) 8.5%	530.5 (18.72) 3.9%	560.3 (19.77) 1.7%
2005 Forecast Demand Annual Growth Rate	556.1 (19.62) 5.4%	588.0 (20.75) 3.0%	596.0 (21.03) 1.5%
2010 Forecast Demand Annual Growth Rate	600.3 (21.19) 4.1%	641.5 (22.64) 2.6%	661.3 (23.34) 1.7%
2015 Forecast Demand Annual Growth Rate	675.3 (23.83) 3.7%	693.8 (24.49) 2.3%	712.3 (25.14) 1.6%

These forecasts yield growth rates of 3.9 per cent and 2.3 per cent for the 1995-2000 and 1995-2015 periods, respectively. Most of the growth is expected to occur in the electric generation sector as a result of deregulation and restructuring toward a competitive market. Retirement of uneconomic generating capacity and the development of efficient gas-fired combined-cycle generation units is expected to increase demand for gas. Alliance contended that fuel efficiencies for gas-fired plants tend to be about 50 per cent higher than coal-fired plants (10.5 MJ/kWh or 10,000 Btu/kWh for coal versus 6.8 MJ/kWh or 6,500 Btu/kWh for gas) which makes gas competitive, even if its price on a heat-equivalent basis were higher.

The Reed Study also analyzed the market potential by utilizing five different scenarios of the market share that Canadian gas is likely to capture: (i) a 14.3 per cent share of the total U.S. market as per its 1995 share; (ii) a 46 per cent share of the incremental U.S. market; (iii) market share based on a forecast of Canadian exports, assuming a Canadian market share ranging from 13.6 per cent in 1995 to 15.3 per cent in 2000; (iv) market share based on relative gas production and reserves; and (v) the Canadian market share of the U.S. market that would be necessary to fully utilize incremental capacity provided by the Alliance Pipeline.

Based on an assessment of the likely outcomes with respect to market share in these scenarios, the Reed Study suggested that Alliance's capacity would be needed by 2000 or shortly thereafter, even assuming that the 1998 Foothills/Northern Border expansion was completed in advance of the Alliance Project coming on stream.

The Reed Study concluded that, with increased market liquidity and by means of displacement, exchange, and backhauls, Canadian supplies will have access to markets currently served almost exclusively by U.S. gas supplies. Alliance explained the mechanism by which backhauls could work, using St. Louis as an example. Gas on ANR, originally destined for Joliet, could be exchanged in St. Louis for gas delivered to Joliet via Alliance. Alliance led evidence to indicate that this exchange would not result in any incremental cost, but that a small service charge (one or two cents per GJ or MMBtu) might be levied.

In response to an undertaking taken during cross-examination, Alliance provided an updated demand projection based on the EIA's 1998 Annual Energy Outlook (Table 2-3).

Table 2-3
U.S. Market Demand Forecast (Reed Study Update)
10^9m^3 (Tcf)

Year	Minimum	Average	Maximum
1995 Base Demand	503.0 (17.75)	503.0 (17.75)	503.0 (17.75)
2000 Forecast Demand	538.5 (19.01)	551.9 (19.48)	565.4 (19.95)
Annual Growth Rate	1.6%	1.8%	2.4%
2005 Forecast Demand	587.9 (20.75)	603.9 (21.31)	620.0 (21.88)
Annual Growth Rate	1.6%	1.8%	2.0%
2010 Forecast Demand	641.7 (22.65)	660.4 (23.30)	679.1 (23.96)
Annual Growth Rate	1.6%	1.8%	2.0%
2015 Forecast Demand	699.0 (24.67)	718.3 (25.35)	737.6 (26.03)
Annual Growth Rate	1.7%	1.8%	1.9%

The revised outlook uses only GRI and EIA projections, resulting in lower growth rates in demand than those indicated in Table 2-3. Alliance also recognized that the incremental approved export capacity would be 31.5 10^9m^3/yr (1,110 Bcf/yr) by 2000, including that provided by its own Project. In its market analysis, Alliance estimated capacity on its system as 37.5 10^6m^3/d (1,325 MMcf/d) plus an estimated Authorized Overrun Service of ten per cent, yielding a capacity of 40.9 10^6m^3/d (1,445 MMcf/d) for an annual throughput capability of 15.1 10^9m^3 (532 Bcf).

Using the market shares in scenarios 1 and 2, Alliance projected that it would have a 55 to 65 per cent utilization rate in 2000 and a 100 per cent utilization rate in 2005. Alternatively, Alliance would have to capture 14.2 per cent of the market share in its seven market regions for full utilization in 2000, compared to the 9.3 per cent for which Canadian gas accounted in 1995 (scenario 5). The market shares with respect to scenarios 3 and 4 were not submitted with the update.

Alliance stated that it was not privy to the details of the marketing efforts or downstream transportation arrangements made by its shippers, but expects that its shippers will either sell to end-users in Chicago, access transportation service on existing pipelines, enter into swaps/exchanges, or access transportation on new pipeline facilities.

Incremental gas markets may exist in Ontario due to the potential closure of nuclear generating stations. Alliance's assessment is that not all of these plants will return to service because they will not be economical sources of power generation. Alliance estimated the incremental natural gas market for electricity generation in Ontario to be between 4.93 and 7.03 $10^9 m^3$/yr (174 and 248 Bcf/yr).

Alliance argued that Canadian gas will be competitive with U.S. gas. Alliance surmised that U.S. gas, particularly from the Gulf Coast, would have production costs that are approximately double those from the WCSB, which would make Canadian gas more attractive in the Chicago market. In conclusion, Alliance argued that gas flowing on its system would capture additional market share in the U.S., both in the Chicago market and in other connected markets.

Views of Intervenors

Foothills was of the view that Alliance's demand forecast was overly optimistic. Foothills examined all recently-approved natural gas export expansions (TCPL 1996/97 and 1997/98, Foothills 1998 Eastern Leg Expansion, and Maritimes & Northeast Pipeline) and concluded that the Alliance Project was not necessary to satisfy the expected incremental demand in the near term. Foothills noted that the Board had approved additional export capacity of 8.6 $10^9 m^3$/yr (304 Bcf/yr) to Midwest markets and an additional 7.65 $10^9 m^3$/yr (270 Bcf/yr) to Northeast markets. Adding the planned Alliance volumes of approximately 15.1 $10^9 m^3$/yr (532 Bcf/yr) would result in the addition of 31.3 $10^9 m^3$/yr (1,106 Bcf/yr) of export capacity by the year 2000.

Foothills examined incremental regional demand, based on evidence provided by Alliance in an appendix to the Reed Study. After some intermediate calculations, Foothills showed its estimate of incremental demand, relative to 1995 (Table 2-4).

Table 2-4
U.S. Incremental Demand Forecast (Foothills)
$10^9 m^3$/yr (Bcf/yr)

U.S. Market Region	Incremental demand 2000	Incremental demand 2005
Midwest	10.65 (376)	29.4 (1,038)
Northeast	7.82 (276)	17.3 (612)
Gulf Coast	9.78 (345)	26.3 (928)
South Atlantic	16.0 (565)	28.7 (1,013)
Total	**44.26 (1,562)**	**101.8 (3,592)**

Foothills concluded that Canadian exports would need to capture 71 per cent of all incremental U.S. demand if the new pipelines, including the Alliance Pipeline, were to operate at a 100 per cent utilization factor in the year 2000. Foothills also suggested that the Midwest and the Northeast were the only market areas directly connected to Alliance and that Alliance would need to capture 170 per cent of the market increment in these two regions to attain full utilization. In other words, significant displacement of U.S. supply would have to take place in these markets. This was disputed by Alliance, which indicated that gas carried by Alliance could access the Gulf Coast and South Atlantic markets by exchange and backhaul, and that there could be some displacement of U.S. gas in these two regions. Alliance acknowledged, however, that the Reed Study was not in any way based on discussions of the U.S. market with Alliance shippers.

Foothills stated that price differentials (in American dollars) between Chicago and New York averaged about $0.31/GJ or $0.33/MMBtu during the September 1996 to March 1998 period, whereas information extracted from ANR's website showed tolls on proposed pipelines from Chicago to New York of $0.82 to $0.98/GJ or $0.86 to $1.03/MMBtu. Foothills contended that gas would not flow on these pipelines as the price differential was substantially less than the toll. Alliance maintained that the New York price would likely rise, but did not come to a firm conclusion regarding the magnitude of the increase.

Foothills filed a study by the Brattle Group entitled "An Assessment of the Impact of the Alliance Project and its Implications for Foothills Pipe Lines Ltd". This assessment concluded that there is no incremental market demand to support the Alliance Project. More specifically, it argued that the Reed Study had three major flaws: (i) it ignores the effects of additional capacity being provided by TCPL and Foothills/Northern Border expansions prior to Alliance's in-service date; (ii) the market area is too broad; and (iii) the study contains numerical and conceptual mistakes. It questioned the definition of the market area, the measurement of base year demand, and market share assumptions. The Brattle Group Study concluded that only the Midwest and the U.S. Northeast should be recognized as potential markets for Alliance.

Foothills concluded that, if the Alliance Project were approved and built on schedule, there would be excess export capacity from the WCSB to U.S. markets. Foothills therefore argued that some existing pipelines, including its own, would be underutilized for a significant period of time until market demand caught up with pipeline capacity. Foothills asked the Board to take this potential impact into account in making its determination on the application.

Views of the Board

The Board notes that a project like that applied for by Alliance must attain a minimum scale in order to be viable. The addition of a new large-diameter pipeline will, of necessity, result in large volumes of gas suddenly coming onto the market.

The Board tends to agree with Foothills that, with the current expansions of Foothills and TCPL, the U.S. Midwest market will be well served by Canadian gas supplies. With the addition of the Alliance Project, it is likely that Canadian gas will have to move to U.S. markets further east and south through existing and new pipeline connections, and through displacement sales.

The Board expects that additional Canadian gas will be sold in markets in both the U.S. Northeast and Eastern Canada, either directly through interconnections with the Alliance Pipeline or indirectly through swaps and exchanges. The Board also accepts that some gas may be marketed in non-traditional markets such as the South Atlantic and Gulf Coast. However, these latter sales will tend to be short-term and not necessarily indicative of sustainable market sales. In the Board's view, the inclusion of these non-traditional markets in Alliance's market assessment is not warranted at this time given the pattern of gas sales in the North American gas market.

Canadian gas will probably displace some U.S.-sourced gas in the Midwest market and, as a result, Canadian gas may gain a large share of the incremental demand in this market. Production costs in the WCSB compare favourably with production costs in U.S. basins and recent history indicates that Canadian gas has the potential to capture a large share of the growth market in the U.S. However, this may be achieved only if Canadian producers are willing to compete aggressively on the basis of price.

The Board is satisfied that markets will be sufficient to support the Alliance Pipeline over the life of the Project. Canadian gas producers have demonstrated that they can compete successfully in U.S. markets and the long-term outlook for gas demand in the U.S. appears to be robust. The financial commitments of the Alliance shippers to the Project provide strong evidence that the market will be adequate. The Board recognizes the shippers' business expertise and their confidence that the market opportunities merit the investments to which they have committed.

The Board accepts that it may initially be difficult to market the large increment of gas able to flow into U.S. markets, and that capacity on the Alliance Pipeline or on existing pipelines may not be fully utilized for some time following completion of the Project. The possibility of some period of underutilization is inherent in launching a large-scale greenfield natural gas pipeline.

2.4 Shipper Commitments and Project Financing

2.4.1 Shipper Commitments

In the fall of 1996, Alliance conducted an open season for the subscription of firm transportation service on its proposed pipeline. This process resulted in subscriptions being taken by 37 shippers for 36.8 $10^3m^3/d$ (1,300.3 MMcf/d) or approximately 98 per cent of the available firm capacity for terms of 15 years.

Alliance filed pro forma copies of both the Precedent Agreement that had been entered into by each of the shippers and the Transportation Service Agreement that would be executed once the conditions precedent have been met. The Company also reported that comparable precedent agreements for matching capacities had been executed by Alliance Pipeline L.P. and shippers on the U.S. portion of the pipeline.

Alliance initially reported the open season results in aggregate terms, arguing that the Project would be adversely impacted if the identities of the shippers and the details of their commitments were to be publicly disclosed. This position was challenged by certain of the intervenors and was the subject of a pre-hearing motion.

The Board was not persuaded of the need for confidential treatment and directed Alliance to provide a listing of the shippers and the respective individual contracted capacities. This listing has been reproduced as Table 2-5.

Under the terms of the Transportation Service Agreement, shippers are required to pay the applicable demand charges regardless of the volumes actually tranported on the pipeline. Alliance reported that the 98 per cent subscription level translates into an aggregate financial commitment to the Project of approximately $4.7 billion during the first 15 years. When the corresponding commitments relating to the U.S. segment are included, shippers have made commitments to pay approximately $8.2 billion (Canadian).

Alliance submitted that shipper subscriptions and the attendant commitments to pay demand charges, which were made in the face of other existing and proposed transportation options, represent a solid endorsement of the Project and constitute compelling evidence of the need for the new pipeline capacity that it would provide. This position was backed by CAPP, the WCPG, and certain other intervenors, including individual Alliance owners and shippers.

2.4.2 Project Financing

The capital structure of the Alliance Project is anticipated to be 30 per cent equity, consisting of the general and limited partner contributions, and 70 per cent debt. The Company is targeting an annual rate of return of 12 per cent on equity and estimates an annual effective interest rate of 6.70 per cent.

To obtain its debt financing, Alliance and its financial advisors, Goldman, Sachs & Co. and ScotiaMcLeod Inc., actively marketed the Project within the banking community. The Project was promoted on the basis that 37 shippers had signed 15-year transportation contracts for 98 per cent of the capacity, that the proposed toll structure of the pipeline reflects a reasonable allocation of risk between the pipeline and its shippers, and that the Project offers a competitively-priced, market-responsive service.

Alliance indicated that it had firm commitments for all of the equity, and that its lenders have underwritten all of the debt financing on a non-recourse basis.

During the proceeding, Foothills requested that Alliance be required to produce its commitment letter to the banks so that the Project's financing arrangements could be effectively tested. Alliance argued that provision of the requested document could put it at a competitive disadvantage because of its sensitive nature. The Board took the positions of both parties into consideration, exercised its powers pursuant to section 16.1 of the *NEB Act*, and permitted the letter to be filed with the Board on a confidential basis. The Board also directed Alliance to produce a summary of the letter for the hearing record.

No concerns were raised about Alliance's ability to finance the construction and operation of the pipeline.

Table 2-5
Alliance Pipeline Ltd. Shippers
(as of 21 January 1998)

	Contracted Capacity	
Shipper Name	**$10^3m^3/d$**	**MMcf/d**
AEC Marketing	1416.4	50.0
ANR Alliance Transportation Services Company	4128.8	145.75
Apache Canada Ltd.	141.6	5.00
Beau Canada Exploration Ltd.	529.7	18.70
Cabre Exploration Ltd.	283.3	10.00
Canadian Hunter Exploration Ltd.	1416.4	50.00
Canadian Natural Resources by its Managing Partner Canadian Natural Resources Limited	708.2	25.00
Canadian Occidental Petroleum Ltd.	424.9	15.00
Chauvco Resources Ltd.	2124.6	75.00
Chevron Canada Resources, a Partnership by its Managing Partner, Chevron Canada Resources Limited	849.8	30.00
The Consumers' Gas Company Ltd.	2124.6	75.00
Cordeca Corporation	1458.9	51.50
Crestar Energy by its Managing Partner Crestar Energy Inc. (Including Grad and Walker Energy Corporation)	1447.6	51.10
Duke Energy Marketing Limited Partnership	849.8	30.00
Duke Energy Resources Management Company	1905.0	67.25
Encal Energy Ltd.	566.6	20.00
Gulf Canada Resources Limited	1416.4	50.00
IPL AP Holdings (U.S.A.) Inc.	849.8	30.00
MAPCO Canada Energy Inc.	283.3	10.00
Newport Petroleum Corporation	212.5	7.50
Northstar Energy Corporation	566.6	20.00
Penn West Petroleum by its Managing Partner Penn West Petroleum Ltd.	141.6	5.00
Petro Canada	2407.9	85.00
Pinnacle Resources Ltd.	283.3	10.00
Poco Petroleums Ltd.	708.2	25.00
ProGas Limited	1841.3	65.00
Ranger Oil Limited	793.2	28.00
Remington Energy Ltd.	566.6	20.00
Rigel Oil & Gas Ltd.	424.9	15.00
Rio Alto Exploration Ltd.	212.5	7.50
Star Oil & Gas Ltd.	113.3	4.00
Summit Resources Limited	424.9	15.00
Talisman Energy Inc.	566.6	20.00
Tarragon Oil & Gas Limited	424.9	15.00
Union Gas Limited	2266.2	80.00
Westcoast Energy Inc.	1869.6	66.00
Wintershall Canada Ltd.	85.0	3.00
Total	**36834.6**	**1300.30**

Views of the Board

When shippers make long-term commitments by signing transportation contracts, they have obviously concluded that these commitments constitute the best use of their available capital in comparison to other options. The evidence presented by Alliance has satisfied the Board that shippers committed to the Project after a thorough assessment of the value of the proposed transportation service and the associated risks.

Given the importance of the shipper commitments in support of this application, the Board will include in any certificate which might be issued a condition requiring Alliance, prior to the commencement of construction, to submit an affidavit confirming that Transportation Service Agreements have been executed for the subscribed capacity.

On the basis of the evidence presented, the Board is satisfied with both the ability of Alliance and its partners to finance the Project and the proposed debt/equity structure.

2.5 Economic Feasibility of the Alliance Project

Views of the Applicant

Alliance argued that the hearing record clearly demonstrates that its Project underwent an extensive and thorough review and assessment by the market. Alliance was involved in an intense competition with proposed alternatives and the Alliance Project was chosen by the marketplace, as evidenced by the $8.2 billion that shippers have committed to pay to Alliance through the firm long-term transportation contracts which they have signed.

A broad spectrum of owners, including producers, pipelines, and public and institutional investors, have committed to provide the equity. The evidence indicated that lenders had underwritten all of the debt financing on a non-recourse basis, and were in the process of successful syndication of those loans.

Alliance also argued that it had provided sufficient evidence with respect to the availability of gas to its pipeline and with respect to the markets to be served by the Project. In conclusion, Alliance requested the Board to find that the market has worked effectively and that Alliance has satisfied the economic feasibility test.

Views of Intervenors

WEI submitted that there was no refuting the proposition that the Alliance Pipeline would be used at a reasonable level for the foreseeable future, and that the demand charges would be paid. WEI argued that the Board should find that the Project is economically feasible and justified.

The WCPG noted that producers expressed confidence about supply, markets, and economic feasibility, not by writing reports, but by writing cheques. The WCPG submitted that the Board can and should rely on these commitments and expressions of confidence to conclude that Alliance has satisfied the economic feasibility requirements.

As discussed in section 2.1, some parties made submissions regarding the appropriate test of economic feasibility. However, none of these parties actually argued that Alliance had failed to demonstrate that its Project was economically feasible.

Views of the Board

The Board finds that the Alliance Project is economically feasible; i.e. that the applied-for facilities are likely to be used at a reasonable level over the life of the Project and that the demand charges will likely be paid.

As previously discussed in this chapter, the Board recognizes that, with the completion of the Alliance Project, total take-away capacity from the WCSB may exceed the ability or willingness of natural gas producers to supply gas at prevailing market prices for some period of time after the pipeline is constructed. The Board is satisfied, however, that the Alliance Project will be economically viable. By its actions, the gas producing community has demonstrated strong support for an alternative transportation system. Canadian natural gas producers have repeatedly shown that they can compete effectively in U.S. markets and that they can increase gas production in response to market demand. The evidence provided by Alliance with respect to shipper commitments to the Project and the anticipated financial commitments by the banking community provide the Board with confidence that there is strong commercial support for the Project.

Chapter 3

Potential Commercial Impacts

A large project like that of Alliance can potentially have significant commercial impacts on third parties. These impacts could be beneficial, such as by providing increased choice and competitive benefits to parties other than the shippers on Alliance. They could also be negative, such as offloading gas volumes on existing pipelines, thereby creating financial hardship for the shareholders and/or the customers.

This chapter addresses: (i) the potential impact of the Alliance Pipeline Project on competition and on netback prices to gas producers; (ii) the potential impacts on existing pipeline companies; (iii) the potential impacts on the Alberta petrochemical industry; and (iv) concerns about domestic access to natural gas supplies.

3.1 Competition and Netbacks

Views of the Applicant

Alliance maintained that its application was about competition. This includes allowing markets to work, moving away from monopoly, and offering producers alternative access to markets. Alliance contended that its Project is fundamentally driven by the need for additional natural gas capacity from the WCSB to available markets, and by a desire to provide a competitive alternative to the dominant Canadian natural gas pipelines that currently provide transportation out of the basin.

As a "paradigm shift in energy transportation", Alliance planned to achieve its competitive objectives and hoped to establish a price connection between Chicago and Empress. Alliance estimated that the industry has been foregoing between $3.5 billion and $6 billion a year because of low gas prices. Alliance suggested that it would provide significant benefits to the natural gas industry through increased netback prices to producers.

Alliance stated that one of its main goals is to create fundamental change in the pipeline industry, whereby pipeline capacity leads supply instead of lagging supply as in the past. Alliance noted that Dr. Carpenter, a witness for Foothills, affirmed that some excess capacity, and the attendant costs, are acceptable and that stranded costs must be dealt with on a case-specific basis. He testified that spare capacity provides flexibility and is not necessarily a waste of resources. The WCSB has generally been unable to avoid gas-to-gas competition due to a lack of spare capacity.

Alliance also noted that Dr. Carpenter stated that the public interest is served by maximizing the value of gas production in the WCSB. He explained that if gas production value is to be maximized, the objective should be to optimize the quantity of pipeline capacity needed to connect prices in the WCSB with downstream market prices, and not necessarily to minimize pipeline costs.

Alliance submitted that it will be serving the public interest by building sufficient capacity to connect prices in the WCSB with downstream market prices and by maximizing the value of gas production.

Alliance suggested that it will provide a single, direct route from producer to consumer, resulting in greater certainty in terms of cost, timing, and security.

Alliance referred to the Accord, which states that TCPL and NGTL are supportive of competition. The Accord acknowledges that fostering competition in the pipeline industry is good public policy in terms of the WCSB, even though a role for regulation remains.

Alliance encouraged the Board to decide that competition can and does work within a regulated environment, and that the market has operated so as to create competition and to create a market-based solution to the WCSB capacity constraint.

Views of Intervenors

A number of parties also supported the competition that Alliance would bring to the gas transportation sector.

The 40 members of the WCPG were united in their unconditional support of the Project notwithstanding their diverse interests.[1] The WCPG submitted that new additional export capacity out of the WCSB would assist Western Canadian producers in obtaining higher prices for their gas. The WCPG also argued that the presence of Alliance as a competitive alternative would promote innovation and efficiency in the gas pipeline sector.

In CAPP's view, supporting market choice would be consistent with the Board's views on competition as expressed in MH-2-97[2]: the market should be permitted to operate; undue influence on the market should not be exercised by any individual or small group of individuals; and most importantly, shippers must be permitted to exercise the choice to have access to alternative means of getting their products to market.

CAPP pointed out that the Accord recognizes the benefits of pipeline competition and facilitates resolution of competition issues. In CAPP's view, the Accord, and the intention of the parties who signed it, lays the foundation for an industry solution to many of the issues before the Board. According to the WCPG, the best solutions are market-driven, industry-determined, and competitive, even though a need for regulatory oversight remains.

As stated in the Accord, CAPP emphasized that there must be some reasonable amount of spare or duplicative pipeline capacity which can create competition. Without that capacity, competition is non-existent, because shippers have no choices at the margin.

IPLE and PanCanadian Petroleum Ltd. ("PanCanadian") noted that the competitive service that Alliance is offering has several benefits that may not be available on other pipeline expansions: (i) it is a fieldgate-to-citygate service capable of handling rich gas; (ii) it is a direct transportation service from

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[1] The WCPG comprises 40 producers and marketers of natural gas from the WCSB and includes Alliance owners and non-owners and Alliance shippers and non-shippers. Refer to page (x) for a list of the members.

[2] NEB Reasons for Decision dated October 1997 on an application dated 12 May 1997 by Novagas Canada Ltd. requesting that the Board inquire into the practices of Westcoast Energy Inc. with respect to gas shipping arrangements at Taylor, British Columbia (MH-2-97).

northeastern B.C. and northwestern Alberta to Chicago; (iii) it applies innovative technology that provides economic transportation; (iv) it is a negotiated package of terms and service; and (v) perhaps most importantly, it would provide a competitive influence on other pipelines.

In CAPP's view, "competition" is not just a mantra; it is an essential activity that promotes economic efficiency and provides significant benefits, whether or not the industry in which the competition takes place is regulated. PanCanadian stated that Alliance's competitive impact was one of several commercial considerations of shippers when they elected to commit to paying the demand charges for service on Alliance. PanCanadian supported Alliance because it would likely result in more choice and competitive rate structures. PanCanadian, CAPP, and the WCPG argued that competition among pipelines is healthy and essential to the future well-being of the producing industry.

IPLE submitted that competition in the pipeline business occurs when pipelines vie for subscription to new capacity and that, in this instance, the market has indicated its support for the Alliance Project. IPLE noted that, despite Alliance’s size, the new capacity is still small relative to the existing pipeline capacity. The market power of the incumbent pipelines is still strong, indicating that fully developed pipeline-on-pipeline competition will take time.

Consumers' Gas indicated a preference to encourage competition among TCPL and other transporters, particularly in relation to tolls. One of the gas supply objectives of the company, which sources the majority of its gas supply in Western Canada, is to diversify its portfolio of transportation service agreements. Portfolio diversification enhances security of supply and provides alternative transportation paths to the company's franchise areas.

Union Gas remarked that the Alliance Project is unique because it gives Eastern Canadian markets a competitive alternative source of transportation while, at the same time, allowing Western Canadian producers the opportunity to capture the incremental Canadian market.

Gaz Métropolitain also suggested that Alliance would improve security of supply, although this might occur at the possible expense of medium-term upward pressure on Canadian gas prices.

Some parties did not believe that the Alliance Project would necessarily have beneficial effects for producers and others were concerned about the impact on consumers.

TCPL and Foothills did not agree that the Alliance Project would lead to increased gas prices in the WCSB. TCPL noted that at the time Alliance went to the market for capacity commitments on its proposed system, in early 1996, the industry was characterized by basis differentials in the $1.80 (U.S.) range between prices in Alberta, as measured at the Alberta Energy Company trading hub, and prices in the Chicago area, as measured by prices posted on the New York Mercantile Exchange ("NYMEX"). At that time, supply deliverability in the WCSB significantly exceeded pipeline capacity out of the WCSB by about 14.2 $10^6 m^3/d$ (500 MMcf/d). Alliance shippers were motivated by the prospect that the Alliance Project would narrow price differentials and increase netback prices.

In TCPL's view, recently added and upcoming pipeline capacity has already closed price differentials dramatically from the $1.80 (U.S.) range. TCPL stated that a recent check of the *Canadian Gas Price Reporter* revealed a forward market differential of 52 cents (U.S.) between Empress and NYMEX. TCPL submitted that the target Alliance promoters were aiming for had already been reached.

Foothills agreed that the market already indicates that basin prices have been connected. Through its witness, Dr. Carpenter, Foothills stated that current forecasts of natural gas demand in the U.S. Midwest indicated that demand will be inadequate to support the Alliance Project once already approved projects are taken into account. Foothills contended that if the Alliance Project was built, it would likely result in excess capacity to the Midwest and have significant displacement effects. This excess capacity would, in turn, likely result in reduced netbacks to Alberta relative to what they would have been in the absence of Alliance.

The Industrial Gas Consumers Association of Alberta ("IGCAA") submitted that, while the development of increased competition may be desirable, consideration should be given to the potential impacts on Alberta gas users. The IGCAA was concerned that the Project could result in an increase in prices to Alberta industrial gas users. In the IGCAA's view, the development of competition in a regulated industry demands careful consideration of all parties' interests.

In TCPL's view, the Accord more closely aligns the interests of the pipelines with their stakeholders. TCPL believes that it represents the creation of a platform for the development of both effective incentives for pipelines to expand sooner and competitive pressures upon pipelines' cost control, all towards the continued competitive positioning of the WCSB.

The Consumers' Coalition of Alberta ("CCA"), supported by the Native Canadian Petroleum Association, expressed concern that Alliance will increase gas costs to Alberta customers of natural gas LDCs. Alliance agreed that the impact of Alliance on the Alberta customer might be an increase of as much as $0.60/GJ. The impact on an average residential customer using 150 GJ of gas per year would be an increase of approximately $90 per year based on a $0.60/GJ price increase. For 500,000 residential customers, the province-wide impact would be $45 million per year.

The CCA argued that it was unable to understand how anyone could suggest that the residential customer in Alberta would be well served by the Project. It would not be convenient to that public nor is it necessary to that public that the Project be approved. The CCA suggested that non-residential customers of natural gas would also be adversely impacted.

Views of the Board

The Board is of the view that Alliance is a well-conceived project that will provide an innovative alternative to the existing gas transportation infrastructure. While difficult to measure, the Board believes that there will be large long-term competitive benefits from the Alliance Project. The Board agrees with those parties who argued that Alliance will provide benefits by offering producers an alternative transportation service and by increasing competition among pipelines.

The Alliance Project is strongly supported by natural gas producers in the WCSB who, through CAPP and the WCPG, expressed their desire for choice. The desire for competition and choice is also clearly recognized in the Accord by gas producers, NGTL, and TCPL. Alliance also appears to have received support from natural gas LDCs in Eastern Canada.

It is difficult to predict the specific impact that the Alliance Project will have on gas prices in Alberta and on producer netbacks once it is built. The Board believes that, in the long term, the Alliance Pipeline will help ensure that there is adequate transportation capacity from the WCSB to the major market centres and that the pipeline will have a positive impact on producer netbacks. In the short term, it is possible that Alliance might even reduce netbacks to producers, relative to what they might be in the Project's absence. However, such a result would be a consequence of the lumpy nature of the Project which would result in a very large addition to gas export capacity upon start-up.

The Board is of the view that the long-term competitive benefits of the Alliance Project will be significant and will extend beyond those directly participating in the Project as owners and shippers. Arguably, the presence of Alliance has already contributed to positive changes in the natural gas transportation industry. The Accord indicates that NGTL and TCPL are supportive of and prepared to adapt to increased competition.

3.2 Potential Impacts on Existing Pipeline Infrastructure

3.2.1 NOVA Gas Transmission Ltd.

Views of NGTL and Supporting Intervenors

At the outset of the hearing, NGTL was opposed to approval of Alliance's application. However, after signing the Accord, NGTL modified its position. In final argument, NGTL stated that it neither supported nor opposed the Alliance application, but wanted to draw the Board's attention to its remaining concerns respecting the duplication of laterals on the Alliance Pipeline with NGTL's laterals.

NGTL argued that there would be inadequate supplies of gas at the 35 common NGTL and Alliance receipt points. NGTL provided evidence demonstrating that it would take a minimum of six years from Alliance's originally proposed in-service date for sufficient additional supply to develop at these receipt points to fully utilize both NGTL's existing facilities and the Alliance Pipeline. NGTL noted that its system has been designed, approved, and constructed according to the maximum flow of gas which NGTL expected to be available immediately upstream of each receipt point. At the time that NGTL's facilities were constructed, there was no expectation that other competing facilities might be built in the same areas.

NGTL stated that, while the Accord may not address all of NGTL's specific concerns respecting the Alliance Project, it may result in the reduction of duplication of laterals. NGTL confirmed that the Accord states that costs associated with lower utilization of existing facilities on its system as a result of the construction of Alliance are to be included in NGTL's rates. NGTL also acknowledged that it is willing to resolve any outstanding issues with respect to potential underutilization and interconnection between its system and Alliance outside of the hearing process.

Amoco was concerned that the configuration of the proposed Alliance Project would result in duplication of existing facilities and would produce underutilization costs, particularly on the NGTL system. These costs could be potentially imposed on existing shippers on NGTL. Amoco recommended that the Board provide for a mechanism that sends the correct economic signal to the

Alliance, so that the Company would participate in the costs which would be created through the duplication of facilities and stranded investment on the NGTL system.

Amoco recommended that the Board recognize that construction of the Alliance Project could have a negative impact on existing pipeline systems and that the Board address this issue by requiring Alliance to set aside a contingency fund to help pay for any consequent underutilization. Amoco argued that it is reasonable to require a company that is imposing costs on others to bear part of the burden of those costs.

Amoco argued that duplication, to the degree that it introduces competition in a regulated environment, is not a bad thing. However, to the degree that competition in a regulated environment duplicates facilities, and a new entrant is operating under different rules, then it is reasonable to require a transition mechanism such that the costs imposed by the new entrant are shared equitably among the stakeholders.

Although Amoco took some comfort that, through the Accord, CAPP and SEPAC have supported Amoco's concern relating to the underutilization of the NGTL system, it maintained that the Accord does not provide for cost-sharing by the various parties. To the extent that the Accord imposes additional costs on the remaining captive shippers on NGTL, without assigning any risk or responsibility for those costs on pipeline shareholders, Amoco did not consider itself bound by the Accord.

Amoco cautioned the Board that the Accord should not be taken as providing a proper means for the treatment of underutilization costs. The Accord does not provide any incentive for Alliance to negotiate in good faith with NGTL or to accept any good faith offer made by NGTL. Amoco submitted that it is up to the Board to provide such an incentive by recognizing Alliance's responsibility for sharing in underutilization costs.

Amoco's primary interest is that the principle of cost-sharing be recognized by the Board, not that a specific dollar amount be determined. Amoco felt that it would be reasonable if Alliance were to pay for about half of any underutilization costs.

The IGCAA argued that the Board must consider the overall impact and ramifications of the Alliance Project on those using the NGTL system.

Views of the Applicant and Supporting Intervenors

Alliance maintained that there would be no duplication of facilities. Alliance's position was that it would move gas that was incremental to gas that was already moving from the WCSB. According to Alliance, NGTL is predicting growth of approximately 56.7 $10^6 m^3/d$ (2 Bcf/d) at common NGTL/Alliance receipt points. That growth is over and above the gas that is presently being moved by NGTL through existing facilities.

With B.C. receipt points included, and NGTL's own figures for growth in production at the common receipt points, Alliance argued that there would be sufficient incremental gas to fill 102 per cent of Alliance's firm capacity in the year in which it starts operation, and 120 per cent in the next year. Alliance contended that its pipeline could run entirely full without affecting the total volumes moving on NGTL.

Alliance noted that, even if there were any merit to NGTL's fears of underutilization of its facilities, NGTL would be allowed to recover the associated costs by its shippers, pursuant to the terms of the Accord. After signing the Accord, NGTL's only remaining concern with Alliance was the potential duplication of gas gathering infrastructure, with respect to laterals only. Alliance stated that negotiations on laterals would take place because it made "financial sense for Alliance to prudently pursue options to optimize the system, if opportunities exist".

Alliance stated that the only potential impact on NGTL might be to limit future growth. Alliance noted that NGTL had acknowledged that if the Alliance Project were constructed, NGTL's average annual growth would be reduced over the next several years, from 4 to 5 per cent to 2 to 3 per cent.

Alliance urged the Board to reach the following conclusions based on the evidence respecting the potential for duplication of facilities: (i) there will be no duplication; (ii) Alliance will provide a different service from that provided by NGTL; (iii) any similarity of facilities will be justified by the different service, by the need for choice and a competitive alternative to NGTL, and the operation of the market; and (iv) Alliance will only impact the growth of NGTL, not existing facilities.

Duke agreed with Alliance in suggesting that both NGTL and Alliance will operate at full capacity after Alliance is built.

With respect to Amoco's proposal to establish a contingency fund to cover stranded costs on NGTL, Alliance argued that NGTL's withdrawal of its evidence removed the evidentiary basis for Amoco's position. Alliance argued that the proposal of Amoco and its expert witness, Dr. Safir, did not make sense. Even if there were costs that could be ascribed to duplication of facilities, the evidence was clear that there would also be very substantial benefits accruing to all producers as a result of increased take-away capacity. A contingency fund set up to compensate only for the costs would be inherently unfair.

Alliance's witness, Mr. Engbloom, stated that any compensatory scheme would discourage new entrants from seeking entry into the market, thereby constraining the introduction of desirable competition among pipelines. Secondly, any discipline on costs and service offerings provided by potential new entrants would be muted or eliminated if the pipelines which were unsuccessful in the competition were protected from competition.

The WCPG argued that, if costs were to be shared, then it would logically follow that Alliance should also share in the benefits that its Project would provide to other parties. According to the WCPG, NGTL shippers would actually be better off if some of NGTL's projected load growth were absorbed by Alliance because it would reduce NGTL's required capital expenditures and the need for toll increases. The WCPG submitted that Amoco's request for a cost-sharing mechanism should be rejected.

IPLE noted that competitors often claim that others duplicate the services that they can provide. The example was given that 7-UP does not duplicate Coke; it offers an alternative. IPLE argued that the same principle applies in this case. The industry would be best able to resolve the issues surrounding the interconnection of facilities and minimization of duplication if the threat of alternative facilities were credible.

IPLE submitted that the proposals for stranded asset charges have not been thought through and are unworkable. Under the scheme proposed by Amoco, Alliance shippers would bear a front-end cost that may be incurred on other systems as a result of stranded assets. Even though Amoco only argued for the principle of a contingency fund, this contingency liability would be a real cost that would be borne by Alliance's shippers.

In IPLE's opinion, a contingency fund would hinder a competitive entrant, which is at a competitive disadvantage to begin with against an incumbent service provider. In short, it was argued that it would send the wrong price signal and would remove the competitive threat.

Amoco accepted that NGTL did not have an exclusive franchise to gas supply or shippers. Similarly, Foothills accepted that it did not have an exclusive franchise. IPLE stated that these parties, nonetheless, would have the Board impose a financial obligation on Alliance shippers for any loss by the existing pipelines related to gas supply or the shippers' business. It was argued that the suggestion for cost sharing is illogical if one accepts that the gas supply and the shippers' business is not exclusive to the existing pipelines.

IPLE submitted that, by virtue of the Accord, NGTL and TCPL had accepted the risk that there may be adjustments to existing facilities in the transition to a more competitive environment. IPLE submitted that those adjustments are manageable costs for the greater benefits to be achieved.

ProGas indicated that it is, and would remain, a significant shipper on existing systems such as NGTL. The company was not convinced by the evidence filed by NGTL that there would be underutilization and stranded facilities on its system. The possibility of duplication of facilities, particularly laterals, was foreseen by ProGas. ProGas suggested that an Alliance/NGTL interconnection near Windfall, Alberta or Edson, Alberta would minimize the duplication of facilities.

ProGas commented that, while statements by Alliance on the hearing record and by NGTL in the Accord that they will negotiate are to be applauded, there is no assurance that the two competitors will be sufficiently motivated to negotiate in good faith. However, ProGas stated that it was prepared to rely on the undertakings by Alliance and the spirit of the Accord to motivate the parties to facilitate appropriate interconnections and to minimize duplication of facilities and any corresponding toll increases on the NGTL system.

Union Gas stated that it would not support Alliance if there was any credible risk of material under-utilization of either the NGTL or TCPL systems. Both Union Gas and Consumers' Gas already forecast a requirement for additional transportation into their respective franchise areas, even after Alliance is taken into account.

WEI submitted that the imposition of a contingency fund or exit fees would not be in the public interest, and suggested that such proposals are impractical and represent an attempt to impose obligations upon shippers which simply do not exist.

Views of the Board

By virtue of the Accord, NGTL and shippers, as represented by CAPP and SEPAC, have agreed to negotiate the issues associated with possible underutilization of NGTL's facilities and interconnection between Alliance and NGTL. The Board is confident that, where an adequate economic incentive exists, the parties will come to reasonable commercial agreements without the need for regulatory intervention.

The Board notes that the potential for some duplication of facilities is inherent in the nature of competition. If commercial negotiations do not completely eliminate potential duplication, it will likely be due to the parties' judgement that they are willing to compete in certain areas. In the Board's view, duplication which results in beneficial competition may be considered to be in the public interest.

The Board notes that Amoco's contingency fund suggestion was not supported by other parties. The Board finds that there is little merit in the suggestion, particularly given the willingness of the affected pipeline companies to negotiate a settlement. It is not clear that there will be any costs imposed on third party shippers on other pipelines. Without any certainty of these costs, the Board believes that it would be unfair to saddle Alliance with the onerous financial requirement to create a contingency fund.

Moreover, the Board agrees with those parties who argued that the Alliance Project will create benefits for third parties. Therefore, it would be unreasonable to require Alliance to compensate third party shippers for potential costs when these shippers may, in fact, receive indirect benefits from the Project due to potentially higher netbacks, greater choice, and the increased competition that will take place among gas transportation providers.

3.2.2 Northwestern Utilities Limited

Views of Northwestern Utilities Limited

Northwestern Utilities Limited ("NUL") argued that this application involved both competition and the negative impacts that the Alliance Project would have on other utilities. NUL argued that the interconnections that Alliance had planned with the Paddle River and Cherhill gas plants (situated at receipt points 49 and 50 on Figure 1-3) would have negative consequences for NUL.

NUL argued that the entire volumes currently being produced at Paddle River and Cherhill are essential, on peak day, for the integrity of the NUL system. Unless the gas was available from those plants, dire consequences could befall the Edmonton market, save and except that, as a prudent utility, NUL would do what was necessary to avoid those consequences.

NUL noted that the Cherhill Lateral's design capacity is 462 $10^3 m^3$/d (16.3 MMcf/d) and that its ultimate capacity is 850 $10^3 m^3$/d (30.0 MMcf/d), both of which exceed the current capacity of the Cherhill Plant. The Paddle River Lateral's design capacity is 742 $10^3 m^3$/d (26.2 MMcf/d) and its ultimate capacity is 1,133 $10^3 m^3$/d (40.0 MMcf/d), which would be able to take 75 per cent and 100 per cent of current flows from the plant respectively. On a combined basis, the two laterals could take approximately 90 per cent of current flows from these two plants. NUL asked the Board to make a finding of fact that gas from these plants, at its historical volumes, is essential to its current peak day design.

NUL suggested that if it had to pursue options other than obtaining gas from the Cherhill and Paddle River Plants, such as buying gas from Alliance shippers, it would have to pay a premium that would most likely be equivalent to the cost of constructing new alternative facilities. According to NUL, the cost of constructing alternative facilities would be in the order of $11 million.

NUL argued that Alliance should be required to build an interconnection with the NUL system, through which it could access gas from the Cherhill and Paddle River plants. In NUL's view, the evidence in support of an interconnection between itself and Alliance was uncontested. NUL argued that such an interconnection would be preferable from a supply and engineering point of view, that it would avoid duplication, and htat it would be fully consistent with Alliance's objectives. However, if an interconnection were to take place, some adjustments would have to be made to Alliance's tolls.

NUL noted that its facilities were approved by the Alberta Energy and Utilities Board (and its predecessors) as being in the public interest. NUL argued that it would be unfair for its customers to pay more for their gas in order for Alliance shippers to increase their profits.

Views of the Applicant

Alliance argued that the NUL Paddle River system would not be offloaded by Alliance but would continue to carry gas and be used by NUL to serve its customers. The revenue loss calculations by NUL assumed a worst-case scenario that could not occur if recent production levels at the Paddle River Plant could be taken as an indication of future trends. Alliance facilities would not have sufficient capacity to completely offload the NUL Paddle River system, which was the basis for the NUL revenue loss estimate.

Alliance submitted that, if volumes flowing on the NUL Paddle River system did become a problem, NUL would have the option of buying gas at the Paddle River or Cherhill Plants. Alliance suggested that another option open to NUL would be to construct additional facilities. NUL had acknowledged that the construction of additional facilities was inevitable at some point in time and that NUL would have to study its options.

Alliance stated that it was not at all convinced that NUL's proposed interconnection would be consistent with Alliance's objectives. Alliance also noted that NUL had acknowledged that it would be inappropriate for the Board to direct Alliance to interconnect with NUL or to place Alliance in a disadvantageous position in negotiating with NUL.

Alliance submitted that the best approach would be for the Board approve the Paddle River and Cherhill Laterals as proposed, and leave it to Alliance and NUL to pursue a commercial solution to NUL's concerns.

Views of Other Intervenors

The IGCAA agreed that the proposed construction of the Paddle River and Cherhill Laterals by Alliance threatens the security of supply for thousands of NUL's customers and noted that the cost of constructing any additional facilities would likely be borne by NUL's customers. The IGCAA supported the interconnection between NUL and Alliance, but proposed a connection that was both a receipt and delivery point. The IGCAA did not agree with NUL's suggestion that any interconnection to Alliance should be limited to pipelines.

In the WCPG's view, NUL is attempting to use regulatory intervention to effect a result where Alliance could only access the gas at the Paddle River and Cherhill Plants by using NUL's facilities. The WCPG suggested that NUL would like the Board to guarantee that result by denying Alliance the opportunity to construct its Paddle River and Cherhill Laterals.

The WCPG recommended that the Board reject NUL's argument because the best solution would be a market-based solution, rather than a Board-mandated solution. The WCPG argued that if the Board denies Alliance the opportunity to construct the two laterals, Alliance would be compelled to reach a commercial arrangement with NUL to obtain access to Paddle River and Cherhill gas.

Views of the Board

The Board finds some merit in the argument that NUL could be negatively impacted if Alliance builds lateral connections to the Paddle River and Cherhill Plants.

At the same time, the construction of these laterals would provide gas producers in the areas of these plants with an alternative outlet for their gas production. NUL would be free to compete with other gas buyers for the available gas production in the area. It is possible that NUL will have to pay more for gas moving through these plants than they would have paid in the absence of the Alliance Project; however, the Board finds that this would be a natural outcome of a competitive market process.

The Board has not been persuaded that there are sufficient public interest reasons for it to intervene in the Alliance Project in the manner suggested by NUL.

3.2.3 Foothills Pipe Lines Ltd.

Foothills submitted that the shippers which have contracted for approximately 36 per cent of the capacity on Alliance have no gas supply arrangements in place. Foothills argued that if shippers on Alliance did not have supply under contract, they would be competing for the gas supply which would otherwise be transported on existing pipeline systems. Thus, the Alliance Project could result in underutilization of existing pipeline facilities, including the Foothills system.

In Foothills' view, the Board could approve the Alliance Project even in the face of a lack of evidence on supply adequacy. However, if the Board did so, then it would have to be aware of the potential lack of sufficient supply to fill all of the proposed and existing pipeline capacity and the consequent underutilization of pipeline facilities.

Foothills requested that the Board make a number of findings, including:

(i) recognition that existing pipelines regulated by the Board should be given the option of providing a menu of tolls and services which could be individually packaged and negotiated;

(ii) recognition that the contract renewal policies now in place for existing Board-regulated pipelines have been restrictive and must be altered; and

(iii) affirmation of the principle of reallocation of pipeline costs amongst shippers in the event of underutilization of pipeline facilities constructed under the previous paradigm, when the primary concern was to ensure that only necessary facilities would be constructed.

Foothills believed that the first two findings are necessary to ensure that existing pipelines would have an opportunity to compete with new entrants and thereby have a fair opportunity to ensure that their facilities would not be underutilized. The last finding is necessary to maintain investors' confidence in the existing pipelines.

Alliance argued that the evidence did not support the view that Foothills would be offloaded if the Project proceeded, noting that only 0.45 $10^6 m^3/d$ (16 MMcf/d) of Foothills' contracts will expire between 1998 and 2003. According to Alliance, 52 per cent of the total volume on the Foothills 1998 Eastern Leg Expansion is held with 10-year contracts by shippers who are also Alliance shippers.

In Alliance's view, the concept of capacity development in anticipation of increases in supply is not new. Alliance argued that, if necessary, producers and shippers are willing to pay for the concept of advance capacity to allow competition to work.

The WCPG submitted that the intention of Foothills' evidence was unclear. In the WCPG's view, the Board does not have to rely on the studies of Dr. Carpenter or Mr. Reed but should simply let the market work and rely on decisions made by the market.

Views of the Board

As recognized elsewhere in these Reasons, the Board accepts that there may be some temporary underutilization of existing pipeline systems following the start-up of Alliance, primarily due to the large scale of the Project.

The Board notes that it was presented with an application for certification of the Alliance Project pursuant to section 52 of the *NEB Act*. Tolls and tariffs on pipelines other than Alliance were not an issue at this hearing. The Board does not believe that it is necessary to make any of the findings requested by Foothills. If Foothills or any other federally-regulated pipeline company desires specific regulatory actions with respect to their systems, they are free to make the appropriate application to the Board.

3.2.4 BC Gas Utility Ltd.

BC Gas neither supported nor opposed the Alliance application. Nonetheless, in the interests of its customers, BC Gas raised its concerns regarding the potential impacts that may occur as a result of the construction and operation of the Alliance Pipeline.

BC Gas is almost totally dependent on one pipeline system, that owned and operated by WEI, for the delivery of its gas supply requirements. The company's main concern is that Alliance has the potential to divert gas that would otherwise flow on WEI's T-North and T-South mainline, resulting in underutilization of these facilities and higher tolls for its customers. BC Gas argued that, given WEI's ownership position in Alliance, in any future toll hearings the Board should put the onus on WEI to justify an attempt to pass on the costs of underutilization of its system to its shippers.

BC Gas also raised a concern that the transportation of liquids-rich gas on the Alliance Pipeline will reduce the heat content of the gas delivered to WEI's facilities. It was suggested that this could exacerbate the challenge to provide supply to feed both pipeline systems and could possibly trigger another expansion of WEI's T-South line to enable WEI to maintain its deliveries to downstream customers on an energy-equivalent basis. The consequences of any such expansion would be higher tolls borne by WEI's tollpayers, given that the negotiated settlement between WEI and its shippers calls for rolled-in tolling treatment for mainline pipeline facilities.

WEI submitted that, after Alliance is built, natural gas supply will continue to be available at market prices for consumers currently receiving gas off its system. WEI suggested that supply/demand forces will ensure that gas will be available to B.C. markets. In fact, WEI contended that the Alliance Project will stimulate additional development and production in northeastern B.C.

WEI further submitted that there was no causal link between Alliance proceeding and its future tolls, and that matters relating to its system could be appropriately dealt with in the context of regulatory proceedings specific to WEI.

Views of the Board

The Board notes that BC Gas will continue to have access to natural gas supplies in northeastern B.C. and will be free to compete with other potential buyers for those supplies. The Board also notes that toll and tariff issues related to the WEI pipeline system are outside the scope of this proceeding. Any such issues would be appropriately addressed in separate proceedings pursuant to Part IV of the *NEB Act*.

3.3 Potential Impacts on the Alberta Petrochemical Industry

Alliance has designed its Project to provide shippers with an option to ship liquids-rich gas if market conditions are favourable.[1] Shippers are required to relinquish the rights to their liquids when they deliver their gas to Alliance. In return, they will have their receipts and deliveries balanced such that they will receive, at the delivery point off of the U.S. portion of Alliance, quantities of natural gas equivalent in thermal content to that delivered into the pipeline in Canada. Refer to Appendix VI for a copy of the articles in the pro forma Alliance Precedent Agreement and Transportation Service Agreement relating to natural gas liquids ("NGLs") and liquefiable hydrocarbons.

The evidence suggests that Alliance may build an NGL extraction plant, through Aux Sable Liquid Products LP ("Aux Sable"), near the pipeline's terminus in Chicago. Depending on assumptions, the volumes of liquids which could be recovered at Aux Sable range from 4.77 to 30.2 $10^3 m^3$/d (30 to 190 Mbpd). The Alberta petrochemical industry voiced concern about the removal of ethane from the province and the impacts that this could have on the industry and the Alberta economy.

[1] Further particulars with respect to gas richness are provided in section 5.1.2.

Views of Alberta Natural Gas Company Ltd, NOVA Chemicals Ltd., the Canadian Chemical Producers Association, and the Alberta Department of Energy

NOVA Chemicals Ltd. ("NOVA Chemicals") stated that the Alberta petrochemical industry is a great Canadian success story. Since the inception of the industry in 1979, over $5 billion has been invested in ethane-based petrochemical facilities in Western Canada. Over that time, the industry has achieved an annual growth rate of about 8 per cent.

Ethane is principally used to manufacture ethylene, providing about 50 per cent of the feedstock. Ethane burned as fuel in export markets has a value of about 8.5 cents per kilogram (4 cents per pound) of ethylene. Upgrading ethane into petrochemical derivative products in Alberta results in a product worth 85 cents per kilogram (40 cents per pound) of ethylene, a tenfold increase in value.

NOVA Chemicals filed a study on Canadian and U.S. ethane markets prepared by Marenco Energy Associates ("Marenco"). The Marenco Study noted that, in Alberta, ethane demand for ethylene manufacture was 21.0 $10^3m^3/d$ (133 Mbpd) in 1996, although capacity was about 22.3 $10^3m^3/d$ (141 Mbpd). A further 9.48 $10^3m^3/d$ (60 Mbpd) is used in hydrocarbon miscible flood projects for a total demand of about 31.6 $10^3m^3/d$ (200 Mbpd). Several ethylene plant expansions and new plants are proposed for Alberta. If all were to proceed, ethane demand for feedstock could reach 41.2 $10^3m^3/d$ (261 Mbpd) by 2000. Beyond the year 2000, the outlook is difficult to project. However, Marenco suggested that petrochemical requirements for ethane could reach 53.6 $10^3m^3/d$ (339 Mbpd) based on similar growth rates in the U.S. It is uncertain how the demand for hydrocarbon miscible flood projects will evolve.

Alberta Natural Gas Company Ltd ("ANG"), NOVA Chemicals, the Canadian Chemical Producers' Association ("CCPA"), and the Alberta Department of Energy ("ADOE") were all concerned that Alliance could distort the operation of a competitive market in Alberta for NGLs, in particular ethane. The concerns related to the following elements of Alliance's proposed tariff: (i) the requirement for shippers to relinquish the rights to their liquids; (ii) volumetric tolls; (iii) Authorized Overrun Service ("AOS"); and (iv) physical access to the liquids on the Alliance Pipeline.

NOVA Chemicals recommended that the Board not sanction Alliance's tariff, under which shippers must relinquish their rights to natural gas liquids to obtain gas transportation service. In its view, pipeline services should not in any way be tied to the ownership of the commodity being transported. NOVA Chemicals argued that this tariff provision creates a conflict of interest because ethane on the Alliance system would be indirectly owned by the same companies that own the pipeline. The owners of Aux Sable have a particular interest in having Alliance transport a rich gas stream.

In ANG's view, Alliance creates two classes of shippers: owner-shippers and non-owner shippers. ANG submitted that owner-shippers could use Alliance as a private NGL pipeline since they are the only shippers who could inject, transport, and recover NGLs. ANG argued that this would be a unique and clearly discriminatory arrangement, as all of the other shippers who are not owners of Aux Sable would have no rights to their NGLs once they enter the Alliance Pipeline. Further, the owner-shippers would have the exclusive right to extract not only their proprietary NGLs (i.e. the NGLs they own themselves that would be flowing on the pipeline), but also those injected by the other shippers on the system. ANG argued that this cannot foster a competitive NGL market.

The ADOE stated that market participation would be limited if the Alliance owners were given control of liquids through articles 5.2, 5.3, and 5.4 of the Transportation Service Agreement, rather than having to compete with others to obtain extraction rights at a market price. In the ADOE's view, the Board should not simply accept that because the tariff was negotiated, it is in the public interest. Also, Alliance's inclusion of the required relinquishment of liquids in its tariff seems incompatible with the general trend towards the unbundling of services in deregulated energy markets. The ethane to be transported by Alliance should not be effectively excluded from the market by a tariff approved by a regulatory body.

NOVA Chemicals and the CCPA both objected to the volumetric tolling methodology and the AOS proposed by Alliance (see Chapter 6 for a description of these services). NOVA Chemicals stated that the Board should look beyond the standard cost allocation issues associated with toll design and consider the associated public interest implications. NOVA Chemicals argued that the volumetric toll design provides an incentive for shippers to deliver high heat content gas to Alliance and to inject NGLs into their gas streams. NOVA Chemicals argued that a thermal-based toll would compromise this incentive and the attendant impacts on the Alberta petrochemical industry while still providing Alliance and its shippers with cost-effective new export capacity.

NOVA Chemicals also argued that AOS would provide an additional incentive for shippers to inject NGLs into their gas deliveries to Alliance because there would be no additional charge for this service. It argued that this aspect of the toll design raised further public interest issues that could be addressed most easily by denying Alliance's request for AOS.

Finally, the CCPA, NOVA Chemicals, and the ADOE were concerned with the lack of physical access within Alberta to extract the NGLs transported on the Alliance Pipeline. The CCPA held the view that Alliance would prevent Canadian access to a significant portion of the NGLs produced in the WCSB and this would effectively distort the operation of the competitive market in Alberta for NGLs.

In summary, these parties were concerned that the tariff provisions on Alliance would have the effect of inducing the export of ethane from the WCSB and that the petrochemical industry would not have a fair opportunity to obtain this ethane. The removal of this ethane from the WCSB would limit the future growth potential of the petrochemical industry in Alberta.

NOVA Chemicals stated that Alliance would be capable of removing 9.54 $10^3 m^3/d$ (60.4 Mbpd) of indigenous ethane assuming 42.5 $10^6 m^3/d$ (1.5 Bcf/d) of gas throughput at 40.6 MJ/m^3 (1088 Btu/scf). Furthermore, injection of NGLs could result in as much as 23.4 $10^3 m^3/d$ (148 Mbpd) of ethane leaving Canada in Alliance's enriched gas case. The Marenco Report indicated that, in the absence of the Alliance Project, the Alberta ethane supply/demand balance would be constrained by 2007 to 2008; if 9.48 $10^3 m^3/d$ (60 Mbpd) were to be removed from Alberta on the Alliance Pipeline, potential growth of Alberta's petrochemical industry would be constrained by 2004. The CCPA argued that the future of the petrochemical industry is at risk because of uncertainty regarding the continued existence of its feedstock advantage.

According to NOVA Chemicals, if ethane were exported on Alliance without the opportunity for upgrading in Alberta, then significant adverse economic impacts would result. The Wright Mansell Report, submitted by NOVA Chemicals, suggested that the export of indigenous ethane on Alliance in sufficient quantities to reduce the Alberta supply by 6.95 $10^3 m^3/d$ (44 Mbpd) would result in a net loss of $11.3 billion in Gross Domestic Product to Alberta over 20 years. The impact would be more pronounced if NGL injection occurred or if Alliance's capacity were expanded to 56.7 $10^6 m^3/d$ (2 Bcf/d).

In a study commissioned by the CCPA, Chem Systems estimated that the construction of Alliance as proposed would result in foregone investment and lost opportunity costs of about $3 billion (U.S.) in the year 2000 and up to $7.3 billion (U.S.) in the year 2010.

To address the potential for distortions in the ethane market and to preclude the negative impacts on the petrochemical industry that Alliance would cause, NOVA Chemicals and the CCPA recommended that the following conditions be attached to any certificate which might be issued to Alliance: (i) require Alliance to eliminate article 5.5 of the Precedent Agreement and articles 5.2, 5.3, and 5.4 of the Transportation Service Agreement; (ii) require Alliance to allow NGL consumers physical access to extract and purchase NGLs in Alberta; (iii) require thermal tolls; and (iv) require the elimination of AOS.

ANG supported the first and third of the proposed conditions and the ADOE supported the first condition

Views of the Applicant and Supporting Intervenors

Alliance stated that there was no evidence to suggest that its Project would result in negative impacts on the petrochemical industry, or at least any impacts that warranted intervention by the Board. According to Alliance, there are presently huge surpluses of ethane in Alberta which will continue provided that the natural gas industry continues to grow.

Alliance argued that the ethane supply and demand forecast in the Marenco Report cannot be relied upon. In the report, ethane supply was constrained by the ethane demand forecast, and was limited by a low gas supply forecast with constant gas export demand. Furthermore, the Marenco Report excluded ethane supply from oilsands and refineries. Alliance pointed out that assuming a higher natural gas supply forecast, such as in the Chem Systems Study, would result in an additional 37.9 $10^3 m^3/d$ (240 Mbpd) of ethane at a 75 per cent recovery rate in the year 2010, enough supply for another eight ethylene plants. Alliance also argued that other gas supply forecasts (e.g. NGTL's 2 per cent per year system growth, Sproule's overall supply studies, and GLJ's supply study) support the view that ethane supply will be much higher than suggested by the Marenco Report.

In Alliance's view, the real issue behind the arguments of NOVA Chemicals and the CCPA is one of competition. Alliance argued that any ethane which it might access would also be accessible to the Alberta petrochemical industry. Its shippers are under no obligation to ship rich gas on Alliance. Companies wishing to acquire petrochemical feedstock have many options available to them, including the option of purchasing ethane from the gas plants with ethane extraction capabilities that will be connected to Alliance's receipt points at Taylor, Wembley, Wapiti, Elmworth, and Kaybob III.

Alliance suggested that it was time for NOVA Chemicals to enter the world of competition for ethane feedstock. Alliance stated that it offered nothing more than an additional outlet to producers for ethane produced in Alberta. It is not contrary to the public interest for companies who incur the risk and expense of finding and developing natural gas to achieve a higher value for their product.

In response to the recommendations of the ADOE, Alliance stated the ADOE was asking the Board to deprive the market of the ability to choose. Alliance argued that the Government of Alberta was asking the Board to forbid its shippers from transferring their rights to extract NGLs to the parties of their choice on the terms of their choice. Alliance submitted that, in terms of ethane accessibility, the market has functioned, and that it will continue to function. Regulatory intervention is not required because there has been no market failure.

Alliance noted that there was a possibility that the Aux Sable extraction plant would not be built. Also, Alliance committed in a letter dated 16 December 1997 to the Alberta Minister of Energy that "in the unlikely event that Alberta ethane requirements exceed the supply available from sources other than those indigenous to Alberta gas production delivered into Alliance, [the Company] would be prepared to have an extraction plant constructed on the Alliance pipeline near Fort Saskatchewan on commercial terms acceptable to the relevant parties".

In Alliance's view, the Wright Mansell Report was fundamentally flawed. Alliance submitted that it was simply not credible to argue that its Project would have adverse economic effects due to ethane removal when, in fact, there were substantial surpluses of ethane available to anyone wanting to acquire it at the time that these impacts would allegedly be suffered. Alliance argued that hundreds of thousands of barrels a day of ethane leave Alberta as part of the TCPL, Foothills, and ANG sales gas streams. The fact that 40 per cent of all ethane currently produced in Alberta leaves on those systems to be burned as fuel downstream did not seem to be a problem for Wright Mansell.

Alliance's position was supported by other intervenors, including IPLE, the WCPG, and WEI. IPLE argued that Alliance offers an additional option for ethane, and that the increased exploration and development generated by Alliance would ultimately add to the supply of petrochemical feedstock.

The WCPG argued that NOVA Chemicals and the CCPA want the Board to change Alliance's tolling and tariff provisions in order to provide ethane supply and price protection to the Canadian petrochemical industry. The WCPG submitted that it would not expect the Board to give preference to the petrochemical industry over the gas producing industry. The main issue to be considered by the Board was whether or not Alliance's tolls and tariffs are just and reasonable.

WEI argued that there was no evidence to suggest that the Alberta petrochemical industry would not be able to obtain its required feedstock at prevailing market prices. Shippers have the choice to use either NGTL or Alliance to move their gas with or without entrained ethane.

Views of the Board

The Board does not believe that any features of Alliance's proposed transportation service package are contrary to the public interest.

Representatives of the petrochemical industry argued that they were concerned about the future availability of ethane supply and that the potential growth of the industry could be curtailed by removal of ethane from the province. In the Board's view, the evidence shows that there will be adequate ethane supply for both the currently planned and future expansions of the Alberta petrochemical industry. In this regard, the Board notes that, by providing enhanced market access, the Alliance Project would encourage additional gas production in the WCSB, thereby yielding increased supplies of ethane.

The Board also notes that, currently, only about 55 per cent of the ethane entrained in gas streams flowing on the NGTL system is extracted prior to export from the Province of Alberta. Additional straddle plants and expansions of the existing plants are planned to enhance the availability of ethane feedstock in Alberta.

With respect to the concerns expressed about the requirement that shippers relinquish ownership rights to any liquids entrained in gas streams delivered to the pipeline, the Board accepts that shippers understood the terms of the tariff when they signed Precedent Agreements. The Board also recognizes that many shippers would have the option of removing their liquids prior to delivery into the Alliance Pipeline. The Board is of the view that the real effect of Alliance will be to provide gas producers with an alternative market outlet for their liquids production.

The Board does not believe that physical access to the liquids that will be carried on the Alliance Pipeline will be a significant issue once the pipeline is in operation. The petrochemical industry will be free to purchase liquids from shippers prior to their delivery to the Alliance Pipeline, at least in those cases where shippers have access to extraction facilities. This appears to be the case for the majority of the gas volumes that could be delivered into the Alliance Pipeline. The natural gas streams that could be delivered into the pipeline, and that do not currently have access to deep-cut extraction facilities, represent a small percentage of the total natural gas volumes produced in the WCSB.

The Board further notes that the potential removal of article 5.5 of the Precedent Agreement and articles 5.2, 5.3, and 5.4 of the Transportation Service Agreement was not debated during the hearing, and has not been persuaded that it should render a decision ordering the removal of same. The Board agrees with Alliance that the provision of AOS is a fundamental condition of the Company's arrangements with its shippers, owners, and lenders.

Finally, the Board does not agree with NOVA Chemicals' argument, as contained in the Wright Mansell Report, that the export of ethane entrained in the Alliance gas stream would result in negative economic effects on the Province of Alberta. The Board does not find that the primary premise of the study, that there would be inadequate supplies of ethane for the future expansion of the Alberta petrochemical industry, is valid.

3.4 Domestic Access to Natural Gas

3.4.1 Heartland Gas Initiative

The Heartland Gas Initiative ("HGI") is an association of 13 rural municipalities, 13 towns, three Economic Development Associations, and the Association of Bilingual Municipalities, all located in south-central Manitoba. In April 1997, the HGI was formed to try and persuade TCPL to construct a natural gas pipeline through south-central Manitoba. The HGI's singular objective is to provide natural gas services to farms, businesses, homes, and public institutions in the area.

The HGI advised that all previous efforts to bring natural gas to the area have been thwarted by the up-front capital requirement of some $12 million to construct laterals from the TCPL mainline.

With the suspension of the proposed Viking Voyageur gas pipeline project by TCPL and its partners, HGI is losing the benefit of access to natural gas access from a TCPL mainline at no incremental cost to HGI.

HGI requested that the Board consider a levy to be imposed on "multinational" exporters to assist in providing access to the natural resource that is being exported out of Canada. This contribution could be a percentage of the total infrastructure budget and be set aside for Canadian access.

Views of the Board

The Board notes that the proposal by HGI was raised in final argument and that there was no opportunity to test it during the course of the hearing. Accordingly, the Board is of the view that it cannot properly assess the merits of HGI's proposal. The Board would add, however, that potential gas buyers should attempt to negotiate commercial arrangements with gas suppliers and gas transportation companies under market conditions.

3.4.2 Industrial Gas Consumers Association of Alberta

The IGCAA stated that, while the Alliance Project would provide producers with a transportation alternative to U.S. markets, and U.S. consumers with another source of Canadian gas, it would leave Alberta consumers open to increased tolls on NGTL and potential increases in NUL rates. The IGCAA argued that the Project should only be approved if provision is made for (i) direct access to Alliance by end-users in Alberta and (ii) interconnections with other pipeline systems within the province. In this way, the benefits of improved competition would be provided to all sectors of the industry.

The IGCAA recommended that the following conditions be included in any certificate which might be issued to Alliance:

(i) that Alliance be required to provide the Board with a plan of how existing and future Alliance shippers can or will be able to access Canadian gas consumers;

(ii) that this plan include the potential for direct access to Alliance by Canadian gas consumers and indirect access by way of gas exchanges; and

(iii) that this plan be filed with the Board no later than 31 December 1998.

Alliance stated that it is not opposed to an Alberta delivery point and that it would be willing to consider Alberta deliveries. However, to date there had been no apparent demand for Alberta deliveries, and no shipper had been willing to pay for Alberta deliveries or for additional receipt facilities.

Views of the Board

The Board has not been persuaded that there is an adequate public interest reason to justify adopting any of the conditions that were suggested by the IGCAA. The Board is of the view that it is most appropriate to let potential gas buyers negotiate their own commercial arrangements with gas suppliers and gas transportation companies. If an adequate economic incentive exists, the parties should come to terms without the need for regulatory intervention.

Chapter 4

Socio-Economic and Land Matters

4.1 Socio-Economic Matters

4.1.1 General

Alliance identified socio-economic issues through the compilation of a list of issues from sources including: (i) municipal, provincial, and federal government agencies; (ii) special interest groups such as the Alberta Wilderness Association and the Saskatchewan Environmental Society; (iii) First Nations; (iv) the general public via the Early Public Notification Program; and (v) information in the public domain such as municipal plans, forest management agreements, maps of registered fur management areas.

The study area included all municipal designations crossed as well as all communities potentially affected due to proximity to the Project. Since the effects on communities would be dependant on the size and range of goods and services available, communities with populations greater than 1,000 and within 40 km of the Project, and those with populations less than 1,000 within 10 km of the Project, were included. Major population centres along the Project mainline route include Edmonton, Regina, and, to a lesser extent, Grande Prairie.

The issues identified were grouped into three categories: (i) employment, non-labour impacts, and income; (ii) municipal services; and (iii) quality of life.

Those socio-economic effects directly resulting from changes in the environment are addressed, pursuant to the *CEAA*, in the CSR.

4.1.2 Employment, Non-Labour Impacts, and Income

Due to the highly-automated nature of the pipeline system, the majority of employment associated with the Project would be short term and would occur during the construction phase. Alliance estimated that direct employment associated with the construction of all aspects of the Project, including the mainline, laterals, and operations and maintenance offices, would total approximately 4,485 person-years (see Table 4-1). Approximately 60 per cent of the work would be generated in Alberta with the remaining 30 per cent and 10 per cent being generated in Saskatchewan and B.C. respectively. The estimated peak workforces for the mainline summer, winter, and lateral spreads are 500, 530, and 235 workers respectively. Construction on each spread would be sequential with 15 to 20 crews per spread with activity at any given location generally being completed in six to eight weeks.

Alliance stated that it would use its ongoing public consultation process to raise awareness about the timing and the nature of employment opportunities to enhance opportunities for local contractors, service companies, and individuals.

During construction, the Project is expected to create approximately 12,000 person-years of direct, indirect, and induced employment in B.C., Alberta, and Saskatchewan. The economic impact of the

Project would be reflected elsewhere in Canada through the purchase of steel pipe, compressors, valves and other equipment. Alliance estimated that, once operational, 155 people would be directly employed to operate and maintain the pipeline and its associated facilities. Alliance further submitted that annual operating and maintenance expenditures of approximately $35 million would generate approximately 335 person-years of direct, indirect, and induced employment.

Table 4-1
Direct Operations and Maintenance Employment

Office Location	Number of Employees
Head Office - Calgary, Alberta	80
Control Centre - Calgary or Fort Saskatchewan, Alberta	11
Regional Office - Fort Saskatchewan, Alberta	9
Area Maintenance Centres	
- Fort St. John, B.C.	11
- Grand Prairie, Alberta	11
- Whitecourt or Fort Saskatchewan, Alberta	11
- Rosetown, Saskatchewan	11
- Estevan, Saskatchewan	11
Total Employment	155

The mechanisms that Alliance submitted would be used to ensure that local and Aboriginal contractors participate in the Project include: (i) awarding contracts such as for clearing, grubbing, and fencing in connection with laterals separately from the overall mechanical contracts in areas where local contractors have demonstrated capabilities that would meet Alliance's requirements; (ii) appropriately sizing lateral clearing, grubbing, and fencing contracts; (iii) use of construction contractors with field operations in smaller centres for the laterals; (iv) having contractors provide Alliance with a plan as to how local and Aboriginal contractors would be utilized; (v) purchasing agreements with local stores where possible; (vi) creation and updating of a list of location suppliers of goods and services; (vii) use of local and Aboriginal content as one of the criteria in evaluating contractors; and (viii) Memoranda of Understanding ("MOUs") with First Nations' communities which, in part, establish a process to help Alliance and First Nations communities identify employment and business opportunities.

The MOUs with First Nations' communities and the participation of First Nation and Métis persons in the Project are further addressed in section 4.15 of the CSR.

4.1.3 Municipal Services

The issues associated with municipal services include: (i) availability of fixed roof accommodation; (ii) increased demand on medical services; and (iii) increased demand on law enforcement.

Further municipal service issues associated with the location of temporary facilities such as marshalling areas, fire protection, disposal of construction garbage and solid waste, and road damage are discussed in sections 4.2.2, 4.18, 4.13, and 4.14 respectively of the CSR.

Alliance submitted that annual industrial property tax assessments would increase for the rural municipalities in which the Project would be located. Alliance estimated that the annual property taxes paid to municipalities in B.C., Alberta, and Saskatchewan respectively would be approximately $1.4 million, $8.9 million, and $3.5 million (1996 Canadian dollars).

In the event that accommodation shortages are encountered, Alliance would mitigate the problem with the provision of additional beds to hotel and motel rooms, billeting crew members in private homes, renting homes and apartments, setting up temporary recreational vehicle trailer parking in mobile home parks, fair grounds and other space available in local communities, and using accommodations in larger centres to offset shortages in smaller communities. Alliance noted that as much as 25 per cent of the workforce would bring some form of mobile accommodation during summer construction. In respect of the laterals, Alliance noted that a construction camp may be utilized during the winter construction.

Alliance stated that at least one ambulance and a registered emergency medical technician would accompany each mainline, lateral, and compressor station construction crew. Local hospitals would be contacted regarding the timing and nature of construction activities. Protocols for the transfer and treatment of workers would be established with the hospitals.

Crime prevention would be addressed in cooperation with local Royal Canadian Mounted Police detachments. Alliance submitted that, in addition to safety, its orientation program would cover the rules of conduct on and off the job. Alliance further submitted that those persons disregarding the rules of conduct would be released.

The Peace River Regional District ("PRRD") submitted that primary service communities have not been able to access most of the property tax related to petroleum sector activity as most of this activity takes place outside of the municipal boundaries. The PRRD noted that the Project laterals would not pass through either Fort St. John or Dawson Creek, the primary host communities in the region. The PRRD submitted that recent industry growth has placed mounting fiscal burdens on local government and that the municipal infrastructure is deteriorating. The PRRD raised concerns with the possibility of having to shoulder the cost of establishing and maintaining facilities for mobile accommodations. The PRRD raised further concerns with the added costs resulting from short-term demands on health, fire, and police services and the possibility of road repairs. The PRRD proposed its "Fair Share" initiative to address the issue of not being able to access property tax outside of the municipal boundaries. Alliance submitted that this "Fair Share" proposal would not significantly impact the viability of the Project.

4.1.4 Quality of Life

Issues pertaining to quality of life, such as dust and construction noise, noise resulting from the operation of the compressor stations, air quality and visual aesthetics, and public health and safety are addressed in the CSR.

Views of the Board

The Board notes that substantial evidence was placed on the record during the hearing pertaining to the importance of affording meaningful opportunities for the participation of First Nations and Métis in the oil and gas industry. The Board notes that First Nations and Métis participating in the hearing were generally supportive of the efforts undertaken by Alliance to involve their communities in the Project and that those parties with MOUs with Alliance were satisfied with Alliance's commitments to identify and afford opportunities. The Board is of the view that, given the importance of participation in the Project to Aboriginal persons, and since the MOUs do not include all of the Aboriginal persons along the Project route, that Alliance should be required to monitor the success of the commitments identified during the hearing. Accordingly, the Board will include in any certificate a condition requiring Alliance to report on its performance in respect of its First Nations and Métis employment and commercial participation objectives for the construction and operation of the pipeline. The condition would require Alliance to submit the reports on a quarterly basis during construction and annually during the first three years of operation.

In respect of the potential adverse effects of the Project on municipal services, the Board is satisfied with the information provided by Alliance. These effects would be limited to the construction phase of the Project and would either be avoided or minimized through the commitments made by Alliance. In addition, revenue would be generated within the municipalities through the purchase of goods and services. Property tax, which is the focus of the PRRDs "Fair Share" initiative, is a provincial matter.

4.2 Land Matters

4.2.1 Routing and Facility Site Selection

The criteria and the process used to select the proposed route and facility sites are described in section 4.2 of the CSR.

As noted in that section, Alliance made an initial determination to follow existing rights-of-way and chose to generally follow the Cochin Pipe Lines Ltd. ("Cochin") route from Fort Saskatchewan to Chicago because it was considerably shorter than the other potential routes and less environmentally sensitive. As presently configured, the Alliance Pipeline would cross Cochin's pipeline 22 times in Canada.

Citing safety concerns, Cochin asked that the Board direct Alliance to substantially reduce the number of crossings, preferably to one. Alliance stated that there was nothing unusual about the number of crossings and that all of the proposed crossings would be necessary based on a number of factors including safety, practicality, terrain, environmentally sensitive areas, and discussions with landowners.

The technical aspects of Cochin's argument are addressed in section 5.2 of these Reasons.

4.2.2 Corridor versus Specific Route

Alliance stated that in its communications with the public it has been as specific as possible as to the location of the right-of-way and the associated work space and that the majority of landowners have consented to the proposed location. Alliance noted that it had defined a corridor area of notification of 400 m on either side of the proposed centre line and that landowners and tenants whose land fell within this corridor were also contacted.

Alliance proposed that the Board authorize construction within the 800 m corridor to accommodate future route refinements. Alliance further proposed that any modification of the alignment involving a shift of more than 50 m be the subject of a supplementary filing with the Board describing the public consultation process and environmental review of the modification.

4.2.3 Land Requirements

The width of the mainline construction right-of-way would typically be 32 m in width, consisting of 18 m of permanent easement and 14 m of temporary work space that would be used for construction purposes only. Additional temporary work space may be required at areas such as roads, railways, rivers, and streams.

The width of the lateral construction right-of-way would vary from 18 to 27 m in width depending on the diameter of the pipeline, with a maximum of 18 m in permanent right-of-way as per Table 4-2.

Table 4-2
Standard Right-of-Way Configurations

Pipe Size (mm)	Construction Right-of-Way (m)	Permanent Right-of-Way (m)	Temporary Work Space (m)	Additional Work Space at Road Crossings* (m)
660 to 1076	32	18	14	10 by 30
457 to 610	27	18	9	10 by 30
273 to 406	23	18	5	10 by 25
114 to 219	18	18	0	5 by 20

* The four blocks of additional temporary work space at road crossings would be located along both sides of the right-of-way on both sides of the road being crossed. The 10 m width can be reduced to 5 m when abutting other permanent easements.

Mainline block valves would be located at approximate 32 km intervals. At mainline valve installations, Alliance would obtain a surface lease for an 18 m by 30 m fenced site.

For compressor station facilities, Alliance would obtain, through fee simple purchase, approximate 8 ha and 1 ha sites respectively for the mainline and lateral compressor stations. The fenced area for the single unit compressor stations would be approximately 2.5 ha for those without pigging facilities and approximately 3.3 ha for those with pigging facilities. The fenced area for the multiple compressor unit Windfall Compressor Station would be 5 ha. Alliance also noted that it would be attempting to acquire the sites for the eight compressor stations identified for possible future expansion although these are not part of the applied-for facilities. The facilities that would be installed at these sites would be similar to the other mainline block valves, with the exception that side valves for the future compressor station would also be installed. Meter station sites would be approximately one-quarter hectare. Additional land would be required for access roads and electric power lines as further set out in the application.

Alliance committed to meet with all Crown-held and freehold occupants to secure written consent, and in addition, to obtain any land withdrawals and consents from holders of Forest Management Areas and Coniferous and Deciduous Timber Licences.

Alliance stated that current and future land claims areas were identified through consultation with First Nations and any easements or surface land interests required would be negotiated with the appropriate First Nations and the government representatives. The proposed mainline route would traverse two pending land claims, the Alexander First Nation Land Claim Areas near Fox Creek from approximately KP 403 to KP 405 as well as the Alexis First Nation Land Claim from approximately KP 463 to KP 467.

Alliance submitted that it has approached all adjacent pipeline owners along the mainline for permission to use a portion of contiguous rights-of-way as temporary work space and that it intends to utilize shared work space wherever consent is received. As of 15 December 1997, Alliance had obtained permission to share work space along approximately 176 km of the mainline. Alliance noted that it was compiling information on the rights-of-way paralleling the laterals and that formal requests would be made to the owners to use shared temporary work space. Information on agreements or negotiations for shared work space along the laterals would be forwarded to the Board prior to construction.

Alliance noted that the service of notices pursuant to section 87 of the *NEB Act* had commenced and that, as of 17 November 1997, the land acquisition program for the mainline was approximately 80 per cent complete and the program for the laterals approximately 35 per cent complete.

Alliance stated that its land representatives would be present during the construction and reclamation phases of the Project and would serve as liaison between the Alliance employees, contractors, and the landowner community to address any issues that might arise such as off right-of-way concerns or inconvenience to farming or cattle operations.

4.2.4 Safety Zone

Subsection 112(1) of the *NEB Act* regulates the construction of facilities across, on, along, or under a pipeline or excavation using power-operated equipment or explosives within 30 m of a pipeline right-of-way.

Alliance advised persons of the provisions of section 112 of the *NEB Act* through the provision of the Board's publications entitled *Living and Working Near Pipelines*, *Information Bulletin #13 Pipeline Regulation: An Overview for Landowners and Tenants*, and *Pipelines: A Guide for Landowners and Tenants*.

Alliance submitted that all landowners, persons, or companies with an encumbrance registered on the title of any lands lying within 30 m of the pipeline would be served with the Board publication entitled *Excavation and Construction Near Pipelines* to ensure public safety and the protection of the pipeline.

4.2.5 Landowner Concerns

In addition to concerns identified in Alliance's application, several landowners, either participating in the hearing or through letters of comment, identified concerns with the proposed pipeline including: (i) safety; (ii) abandonment; (iii) routing of the pipeline; (iv) loss of existing vegetation and wildlife habitat; (v) impacts on use and enjoyment of the land; (vi) possible effects of heat from the pipeline on crops; and (vii) visibility of compressor stations. These matters are addressed in the CSR and throughout these Reasons.

As part of its ongoing public involvement program, Alliance noted that it is continuing discussions with landowners regarding concerns such as site-specific wildlife enhancement opportunities. Alliance submitted that, if a concern is raised by a landowner, the Company's policy is to work with the landowner to reach a mutually-agreeable solution. Solutions would be established in writing and depending on the nature of the measures identified, would be included in the construction line list. Alliance's Land Manager would be responsible for landowner concerns. Alliance noted that, to date, it had not agreed to any provisions beyond the mitigation measures identified in its application, supplemental information and responses to information requests to address wildlife or vegetation concerns.

Mr. Carter participated in the GH-3-97 proceeding on behalf of clients who are landowners in the County of Grande Prairie and the Municipal District of Greenview, Alberta. Through the written process preceding the oral hearing, and cross-examination during the hearing, Mr. Carter extensively examined matters of concern to his clients.

During the hearing, Mr. Carter pursued the issue of whether Alliance would commit to summer construction where this was the construction timing communicated to landowners. Alliance responded that its land program communicated to its landowners does not include winter construction. Alliance clarified that it considered winter work to be work commencing after the ground is frozen. Alliance submitted that pipeline contracting crews would be required to move off the summer spreads in order to complete the work scheduled for the winter. Alliance further submitted that, if it changes the program that it committed to its landowner community, it would be necessary to communicate these changes to the landowners to identify their concerns and address them in an appropriate manner.

Mr. Carter submitted that Alliance had presented to landowners that much of what it is doing is based upon what other pipeline companies have done in the past. Mr. Carter cross-examined Alliance on the potential impacts on topsoil of the heavy equipment that would be used during construction. It was also confirmed that the 14 m of temporary workspace immediately adjacent to the permanent right-of-way would be subject to traffic from heavy equipment. Mr. Carter explored whether the practice of treating this 14 m as temporary workspace was consistent with industry practice, particularly that of NGTL.

Alliance noted that its understanding was that NGTL's policy was to obtain permanent easement for its full right-of-way, including its entire working area. Alliance submitted, however, that this did not make the practice an industry practice.

Alliance submitted that the negotiation for temporary workspace is a contractual agreement between Alliance and the landowner for a specific period of time. As such, the Company would not hold permanent rights to the land. Accordingly, Alliance submitted that it is simply a contractual agreement and not a land acquisition. Alliance further submitted that activities on the temporary working space, in terms of reclamation and compensable losses and inconveniences, will be treated the same as the permanent right-of-way.

Views of the Board

The Board notes that while Mr. Carter participated in the hearing up to and including cross-examination, he did not provide final argument. As a result, the Board did not receive his submissions in relation to the evidence adduced. With respect to the issue of winter construction in areas where Alliance had communicated to landowners that summer construction would occur, the Board accepts Alliance's commitment to consult with landowners in the event of a revised construction schedule. The Board takes seriously representations and commitments made by pipeline companies to landowners. Accordingly, the Board expects that, as part of Alliance's ongoing public consultation program, the Company will advise the Board of any concerns identified and how these will be addressed in the event that changes to the construction schedule are proposed.

In the absence of argument, the Board assumes that no parties have taken issue with Alliance's proposal to retain only part of the area required for construction as permanent right-of-way. The Board is of the view that, although Alliance's proposed combination of temporary workspace and permanent right-of-way might not be consistent with NGTL policy, Mr. Carter has not demonstrated that it would be inconsistent with industry practice or inappropriate in any way.

The amount of land required for pipeline construction is of concern to the Board because of the potential effects on landowners and the environment. The Board has considered Alliance's proposed land requirements for permanent right-of-way and temporary work space and finds that these are reasonable and justified.

The Board is satisfied with the proposed general location of the Alliance Pipeline. In this regard, the Board has not not been persuaded by Cochin that the number of crossings of its system should override the other criteria used by Alliance is selecting this proposed general location. Site-specific issues relating to utility crossings will be dealt with in the manner outlined in section 5.2.

The Board has considered Alliance's request that an 800 m corridor be authorized but has concluded that approval of such a corridor would not be consistent with the specific route that was communicated to landowners and that the request is not supported by the studies undertaken for the Project.

Re-routes may be identified prior to construction to address considerations such as those identified as a result of pre-construction surveys for wildlife or rare or unique plant species. Addressing these deviations, where known, prior to the process for approval of the detailed route will serve to eliminate confusion for parties involved. Accordingly, the Board is of the view that any certificate issued in respect of the Project should be conditioned to require Board approval of these deviations from the specific route prior to the filing of the plans, profiles, and books of reference pursuant to section 33 of the *NEB Act*.

Given the magnitude of the Project, and the variety of conditions encountered, the Board is of the view that this condition should apply to all reroutes and not just those of greater than 50 m.

Chapter 5

Engineering and Safety Matters

5.1 General

5.1.1 Regulations and Standards

The Project is planned to be designed, constructed, and operated in accordance with the Board's *Onshore Pipeline Regulations*, the latest edition of the CSA Z662 standard entitled *Oil and Gas Pipeline Systems* ("CSA Z662-96" or "the Standard"), and all applicable standards, specifications, and codes that are incorporated by reference into that Standard. Alliance would also comply with other federal, provincial, and municipal codes and regulations where applicable.

5.1.2 Unique Design Aspects

The pipeline would employ high-pressure technology and would be capable of transporting rich natural gas mixtures. As detailed in Appendix I, much of the system is designed to operate at pressures up to 12 000 kPa (1,740 psi). In terms of gas composition, the design is based on an Ultimate Rich Gas Mixture having a 19.6 per cent liquids content and a gross heating value of 44.3 MJ/m^3 (1,188 Btu/scf).

This unique combination of pressure and gas composition would result in the transportation of a denser medium, referred to as dense phase gas. By increasing the density, Alliance would reduce the velocity of the gas flow in the pipeline. Since friction losses between compressor stations would be proportional to the square of the gas velocity, the density of the gas would also reduce the pressure drop, compression requirements, and associated fuel gas usage. Alliance is also able to use a smaller-diameter pipeline, as a dense phase mixture occupies a proportionally smaller volume than more conventional natural gas mixtures. This would result in reduced capital costs and lower power requirements.

5.1.3 Operational Considerations

5.1.3.1 Leak Detection

Alliance also indicated that it would employ a state-of-the-art leak detection program to reduce the risk associated with leaks. The leak detection program would consist of up-to-date supervisory control and data acquisition ("SCADA") equipment in conjunction with real-time modelling ("RTM") and line patrol.

With respect to the SCADA and RTM components of the leak detection program, Alliance asserted that its system would be unique in that there would be pressure and temperature monitors at each mainline valve and at each compressor station. The Company would also measure flow at all of the receipt points using orifice meters. The data would be communicated to the control centre via SCADA and continually monitored and analyzed.

Alliance stated that its leak detection model is based on mass balance in conjunction with transient modelling. The leak detection model would take all of the data from the pressure and temperature gauges and flow meters and place it in a computer program which would perform calculations every one to ten minutes to determine what the actual flow volume and state of the product was at the time of data collection. This data would be compared with the previous calculation and any differences would be evaluated to determine if a leak had occurred.

Alliance submitted that its leak detection system would be able to detect a leak of 566 $10^3 m^3/d$ (20 MMcf/d) within a day and a leak of 2.83 $10^6 m^3/d$ (100 MMcf/d) in approximately one hour. The 2.83 $10^6 m^3/d$ leak would represent an opening in the pipe approximately 50 mm (2 inches) in diameter, which is below the critical defect size that would initiate a rupture.

Alliance also stated that it would perform monthly aerial patrols of the pipeline. Ground patrols along the entire mainline and laterals would also be performed annually using standard gas detection instrumentation.

5.1.3.2 Prevention of Liquids Dropout

Alliance indicated that it would use state-of-the-art modelling and numerous SCADA points to ensure that its system does not enter two-phase flow. Among other things, two-phase flow would have the potential to both impact compressor operations and compromise the leak detection system by giving erroneous meter readings.

The Company indicated that its SCADA system model would have the ability to predict and alarm on any approach to a dewpoint. The alarm would trigger a shutdown before the system entered two-phase flow.

Alliance indicated that even the richest potential gas mixture could be kept out of the two-phase region in the mainline. Nevertheless, Alliance has confirmed that a slug catcher would be installed at the downstream end of the 1067 mm mainline. This slug catcher would provide a contingency in the event that liquid from an upstream gas plant upset somehow escaped the quality control of both the plant and the Alliance receipt point.

5.1.3.3 In-Line Inspection

Alliance advised that it would use the most up-to-date inspection methods, including state-of-the-art in-line inspection ("ILI") tools, to ensure that the integrity of the pipeline is not compromised.

The Company indicated that the entire mainline and lateral system would be designed to accommodate the passage of ILI tools. This would be facilitated by using through-conduit type valves as well as permanent and transportable pig launchers and receivers. Alliance plans on using both magnetic flux leakage ("MFL") and ultrasonic type tools when inspecting its mainline. Alliance also stated that each section of the pipeline would be inspected on a five-year cycle. An initial baseline would be established over the first four years of operation using MFL tools and subsequent runs would utilize either MFL or ultrasonic tools.

Alliance submitted that the safety of the pipeline would be enhanced by using ILI equipment, as defects would be found before progressing to the critical stage. Alliance contended that the full ILI capability and inspection plans would ensure that the pipeline would exceed the industry standard.

5.2 Utility Crossings

The construction of the Alliance Project would involve the crossing of a multitude of utilities, including navigable waters, highways, railways, underground telephone lines, electricity lines, and other pipelines. As noted in section 4.2.1, one of the utilities that would be crossed is the Cochin pipeline system, which is also Board-regulated.

As discussed in that section, Cochin expressed concern over the proposed number of crossings of its pipeline. Cochin also asked that, for any such crossings, Alliance be required to: (i) cross at an angle not less than 70 degrees, (ii) install heavier-walled pipe within 200 m of each crossing, (iii) install crack arrestors before and after each crossing, and (iv) install its pipeline under the Cochin pipeline maintaining a distance of at least 30 cm (12 inches).

Alliance submitted that this series of measures, which it characterized as remarkable, was not justified. With respect to the crossing angle, Alliance indicated that it is industry practice to cross pipelines at the approach angle of the line and that it is not necessary to cross a pipeline at any more than 45 degrees. Alliance further submitted that crossing at a higher angle could introduce a sharp bend which would restrict the hydraulics of the pipeline.

Cochin also indicated that its concerns would not be addressed by the execution of the CAPP Facility Crossing Agreement.[1] While acknowledging that the form is used extensively in industry, Cochin submitted that the provisions in the document are conditional upon mutually agreed upon terms and conditions which have not been reached on many basic issues between itself and Alliance. Cochin went on to state that, without appropriate indemnity and provisions for cost coverage, it would not provide its consent for Alliance to cross its pipeline. Alliance indicated that the CAPP Facility Crossing Agreement was designed to avoid situations where issues are raised and litigated on a case-by-case basis. Alliance further indicated that it would use standard industry practices for crossing procedures, surface facility locations, and financial indemnity of companies whose pipeline facilities are being crossed.

No other utility owner made submissions on crossing matters during the GH-3-97 proceeding.

Views of the Board

The Board is of the view that Alliance may still be able to reach agreement with the owners of the utilities which it may cross and, at the least, should be given an opportunity to attempt to reach such agreements. Accordingly, pursuant to section 108(5.1) of the *NEB Act*, the Board has decided to waive the requirement for Alliance

[1] In June 1993, CAPP's Board of Governors approved the universal Facility Crossing Agreement which was developed by the Canadian Petroleum Association in 1990 to streamline processing of federal and provincial crossing agreements.

to obtain leave to cross other utilities, aside from navigable waterways and railways [1], provided that (i) a written crossing agreement is entered into between Alliance and the utility owner for the construction of any such crossings and (ii) any such crossings are constructed in conformity with CSA Z662-96 requirements. Should Alliance be unable to reach agreement with the utilities which it may cross, Alliance may apply to the Board under section 108 and all other relevant provisions of the *NEB Act* for leave to cross a utility. The Board will make a decision with respect to any such application after hearing from both Alliance and the utility owner.

5.3 Fracture Prevention and Control

5.3.1 Conceptual Overview

Safety and operational integrity of natural gas transmission pipelines are important goals. Pipeline integrity is achieved by planning, controlling, and monitoring a number of elements, all of which contribute to the overall pipeline system integrity. Elements that affect overall pipeline integrity are system design, material specifications, pipe transportation and handling, pipeline construction and inspection, pre-service testing, and operation and maintenance practices. Fracture prevention and control is common to a number of these elements.

The fracture initiation tolerance of a pipe is a measure of the pipe wall's resistance to penetration by a crack or other flaw. Fracture initiation tolerance is also a measure of the pipe's resistance to rupturing once a defect has penetrated the wall. Thus, fracture initiation resistance is the first line of defence and a key element in fracture prevention and control design. Fracture propagation resistance determines the distance at which a fracture will arrest. Control of fracture propagation is a secondary line of defence because once a defect has penetrated through the wall, a risk to public safety, property, and the environment has been created.

Fracture initiation is a function of: (i) the fracture initiation toughness of the steel; (ii) the diameter, wall thickness, and material toughness; (iii) the size of the defect; and (iv) the stress acting perpendicular to the defect. Fracture propagation, on the other hand, is a function of: (i) the fracture propagation toughness of the steel; (ii) the decompression of the gas in the pipeline; (iii) the operating temperature relative to the brittle-to-ductile transition temperature of the steel (which in turn controls the ductility and speed of the fracture); and (iv) the backfill conditions.

An ideal goal of any fracture prevention and control design would be to specify pipe characteristics and operating parameters that would only result in leaks in a pipeline regardless of the flaw size and type. This is not possible because no matter how high the toughness, there is a flaw which would rupture the pipe. As such, fracture prevention and control design must balance and conservatively provide for both initiation resistance and propagation resistance.

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[1] Crossing of navigable waterways and railways are administered by public authorities other than the Board.

5.3.2 The Alliance Context

In its application, Alliance provided only a general approach to fracture prevention and control. After the filing of extensive technical evidence on this subject by TCPL and Foothills, Alliance responded with extensive additional filings. The key filing was a January 1998 report entitled "The Alliance Fracture Prevention and Control Program" which incorporated reports by Clearstone Engineering, R.J. Eiber, Consultant Inc., and Dr. B.N. Leis of the Battelle Memorial Institute.

Alliance's proposed pipeline design approaches the limit of today's technology through a combination of its maximum operating pressure ("MOP"), operating temperature, pipe size, and gas composition. The design parameters for the mainline are listed in Table 5-1.

Table 5-1
Design Parameters for the Alliance Mainline

Diameter	1067 mm (42 inches)	914 mm (36 inches)
Wall Thickness	11.4 mm (0.450 inches)	14.2 mm (0.560 inches)
Pipe Grade	483 (X70)	483 (X70)
Pipe Forming Process	helical and U&O	helical and U&O
Maximum Operating Pressure	8 275 kPa (1,200 psi)	12 000 kPa (1,740 psi)
Maximum Stress, %SMYS	80	80
Minimum Design Temperature	-5°C (23°F)	-5°C (23°F)
Minimum Operating Temperature at MOP	4°C (39°F)	24°C (75°F)

The balance of section 5.3 addresses the basis and particulars of Alliance's fracture prevention and control plan and the issues raised in respect thereof.

5.3.3 Application of CSA Z662 Requirements

Section 10 of the Board's *Onshore Pipeline Regulations* provides as follows:

> *(1) A fracture control design shall be submitted to the Board for approval prior to the construction of a pipeline*
> *(a) if the pipeline is intended to carry hydrocarbons in a gaseous state; or*
> *(b) if the pipeline is to be tested with a gaseous medium.*
>
> *(2) The Board shall approve the design referred to in subsection (1) if the design provides for a level of safety at least equivalent to the level of safety generally provided for by CSA standards.*

In connection with subsection 10(2) of the *Onshore Pipeline Regulations*, the materials clause of CSA Z662-96 specifies pipe steel toughness requirements and explicitly notes that these requirements are intended to provide protection against both fracture initiation and fracture propagation. [1] Included is specific direction on the determination of the mimimum design temperature for notch toughness purposes.[2]

The notch toughness requirements relating to fracture initiation resistance do not technically apply to Alliance since the design parameters are outside the limits of the applicable clause of the Standard. [3] Moreover, while the Standard clearly requires supplementary design measures to provide positive control of fracture propagation (such as the use of higher toughness pipe or the use of specially designed fracture arrest devices), the formula provided as a guide for estimating arrest toughness values cannot be applied to Alliance's design. [4]

Therefore, engineering principles and fracture mechanics methods need to be applied to achieve a conservative design that would satisfy the intent of the Standard.

The Standard is clear in its requirement that, if the fracture driving force is above a certain limit (CSA Z662 specified threshold stresses and the pressure limit), the pipeline must be designed to provide positive fracture propagation control. The standard does not allow for a reduced fracture propagation control in the event that high fracture initiation resistance is achieved.

Views of the Board

The Board notes that Alliance has accepted CSA Z662 as the appropriate standard for the design of the Canadian portion of its pipeline system. The Board recognizes that the complexities associated with Alliance's fracture prevention and control design stem from the fact that there are no explicit requirements in the Standard applicable to the

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1 Reference Clause 5.2.2 of CSA Z662-96 on "Notch Toughness Requirements - Pipe".

2 Clause 5.2.1.2 of CSA Z662-96 states as follows: *The minimum design temperature for notch toughness purposes shall be taken to be at or below the lowest expected metal temperature when the pipe hoop stress exceeds 50 MPa during pressure testing and service under design conditions, having due regard to past recorded temperature data, the minimum fluid temperature that could occur, and the possible effects of lower air and ground temperatures.*

3 The second note to Clause 5.2.2.2 of CSA Z662-96 indicates that "specified minimum absorbed energy values higher than those required by Table 5.1 [of the standard, which is referred to in relation to fracture initiation resistance] should be considered for pipe with both a design operating stress greater than 72% of its specified minimum yield strength and a nominal wall thickness exceeding 12.7 mm". The Alliance design is outside of both these limits for pipe in Class 1 locations.

4 Clause 5.2.2.3 of CSA Z662-96 states as follows: *Where the design operating stress for a gas pipeline or the hoop stress developed by a gaseous pressure-test medium exceeds the applicable pipe threshold stress value given in Table 5.2, Category II pipe shall be required and supplementary design measures to provide positive control of fracture propagation shall be considered. Such measures may include the use of Category II pipe with higher values of absorbed energy or the use of specially designed fracture arrest devices.* The threshold stresses given in Table 5.2 are 240 MPa for 914 mm diameter pipe and 225 MPa for 1067 mm diameter pipe. With its 80 per cent SMYS design for the mainline, Alliance is beyond these thresholds (for Grade 483 pipe, 80 per cent of SMYS is 386 MPa). The formula provided in the note to Clause 5.2.2.3 for the estimation of arrest toughness values, however, is not valid for pipelines at pressures exceeding 8 000 kPa. As well, the formula is for buried pipelines containing gases that exhibit single-phase decompression; in the case of Alliance, there would be two-phase decompression due to the design richness of the gas.

selected design parameters; rather, the Standard requires supplementary design measures to provide positive fracture control. These measures must be developed through sound engineering practices. The Board notes that the measures for achieving a conservative fracture prevention and control design, which would satisfy the intent of the Standard, may differ even among recognized experts.

The Board is of the view that, while CSA Z662-96 does not provide explicit requirements which could be applied to the Alliance Pipeline design parameters, the Company must demonstrate that the fracture design of its pipeline satisfies the intent of the Standard by achieving the required degree of safety and integrity. This onus is reinforced by the preface to the Standard.[1]

5.3.4 Minimum Design Temperature

Alliance developed a fracture prevention and control design based on the minimum design temperature ("MDT") of -5°C. This MDT is specified as the test emperature for the Charpy V-notch ("CNV") test and the drop weight tear test ("DWTT").

In order to determine the MDT, Alliance compiled temperature data from Environment Canada readings taken at relevant locations along the pipeline route dating back to 1964. The data demonstrated that the lowest daily temperature at 150 cm soil depth did not fall below -5 °C at any of the locations.[2] The Company also provided, for each location, the average daily temperature at 150 cm soil depth for each date within seven calendar days of the date of the lowest reading.

TCPL argued that the selected MDT of -5 °C may not be low enough. TCPL filed evidence indicating that minimum daily soil temperatures at a depth of 1 m can be as low as –6.7 °C during the winter months, based on a reading taken at Outlook, Saskatchewan in 1975. The average temperature during the month when the minimum temperature was recorded was –6.09 °C.

Alliance argued that its pipeline will be installed at a depth of approximately 2 m to trench bottom and that the spot soil temperature of -6.7 °C once in twenty years at a depth of 1 m is irrelevant.

Views of the Board

In the Board's view, Alliance has satisfactorily demonstrated that -5 °C is an acceptable MDT for the pipeline, provided that the minimum mid-pipe depth is 150 cm. The onus will be on Alliance to ensure that this minimum mid-pipe depth is achieved.

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[1] The preface to CSA Z662-96 states, in part: *Requirements for abnormal or unusual conditions are not specifically provided for, nor are all details related to engineering and construction prescribed. It is intended that all work perfo rmed within the scope of this Standard meets the standards of safety and integrity expressed or implied therein.*

[2] The lowest measured temperature of -4°C was measured at Ellerslie, Alberta in February 1980.

5.3.5 Fracture Initiation Control

The fracture initiation control design is intended to ensure that a pipeline can tolerate the sizes and types of flaws that could be introduced during manufacturing or developed in service. These may be mechanical damage defects and other part-through-wall and through-wall flaws and punctures.

When designing against fracture initiation, the primary concern is to specify the toughness properties of the pipe material which would tolerate axial flaw sizes subject to the hoop stress (which is typically the predominant stress). This involves specifying the fracture initiation toughness of the steel at the MDT.

The fracture initiation toughness is a function of temperature. To prevent brittle fracture in the pipeline, the minimum operating temperature must be above the fracture initiation transition temperature. Alliance would achieve this by requiring that the all-heat average ("AHA") fracture appearance is at least 85 per cent shear area at the MDT.

Since the required fracture propagation resistance is higher than the CVN toughness which would be obtained from fracture initiation considerations, Alliance used the fracture propagation control CVN energy values for fracture initiation design. For the 914 mm diameter pipe, Alliance used an AHA toughness of 195 J with a minimum individual heat average of 136 J. For the 1067 mm diameter pipe, Alliance used an AHA toughness of 215 J with a minimum individual heat average of 160 J. The maximum tolerated through-wall flaws are 147 mm and 155 mm (5.8 inches and 6.1 inches) for the 914 mm and 1067 mm lines respectively. Alliance also stated that the 914 mm and 1067 mm diameter pipes can tolerate (i) gouge lengths of 247 mm and 290 mm (9.7 inches and 11.4 inches) respectively with depths 10 per cent of the pipe wall thickness and (ii) dents 10 per cent of the pipe diameter.

Alliance stated that the puncture resistance of a pipeline with an essentially static loading, such as from a backhoe tooth, is proportional to the wall thickness and the ultimate tensile stress. Alliance claimed that, since Grade 483 pipe has relatively high tensile strength and the line pipes have substantial wall thickness, the designed pipeline would have excellent puncture resistance. Alliance further stated that its pipeline would have the best fracture initiation resistance of gas transmission pipelines in North America.

TCPL indicated that, while the resistance of the Alliance Pipeline to fracture initiation does not cause any specific concerns, it is not convinced that Alliance would have “generally the best fracture initiation resistance of gas transmission pipelines built in North America". TCPL argued that the steel produced for other customers of the same pipe manufacturers is no different from that produced for Alliance and that, therefore, the fracture initiation resistance of the Alliance Pipeline would not be superior to any other modern natural gas transmission pipeline.

Foothills was of the view that Alliance had submitted a satisfactory fracture initiation control design and that Alliance’s proposed pipeline can be considered to have resistance to fracture initiation comparable to any modern, well-designed natural gas transmission pipeline.

Views of the Board

The Board is satisfied that the CVN energy values obtained by Alliance from fracture arrest considerations provide acceptable tolerance of defects for fracture initiation. The Board notes that the specified DWTT of 85 per cent shear area at the MDT ensures that any fracture would initiate in a ductile mode.

5.3.6 Minimum Operating Temperatures

Alliance advised that the minimum operating temperatures for fracture propagation design are 4 °C for the 1067 mm diameter pipe at an MOP of 8 274 kPa and 24 °C for the 914 mm diameter pipe at an MOP of 12 000 kPa.

To control operating pressures and temperature, Alliance has committed to installing a state-of-the-art SCADA system with pressure and temperature measurement at every block valve (spaced at approximate 32 km intervals). Alliance stated that this system would be programmed with the allowable pressure and temperature limits to ensure that the pipe is operated within the range which was considered in the fracture propagation control design.

Alliance committed to further ensure that, if SCADA communication is lost at any compressor station or at either of the two subsequent mainline block valves, the local discharge pressure control set point would be lowered to ensure that the line is always operated well within the range of its fracture arrest toughness capability.

Alliance stated that, if necessary, it would use cooler by-pass and recycle heating to prevent temperatures and pressures from exceeding the fracture control requirements anywhere along the pipeline.

TCPL argued that the after-cooler by-pass and recycle heating may not be an effective means of preventing the temperature drop within the required time.

To support its contention, TCPL performed a shut-in test on its 914 mm diameter Line 100-3 at Station 17 and monitored the conditions at Station 13. The distance between the two stations is 105 km and the elevation difference is 7 m. The experiment showed that the gas temperature from the time of the line isolation stayed almost constant, demonstrating isothermal rather than adiabatic behavior.

Views of the Board

The Board acknowledges that operating temperature is an important consideration in fracture propagation analysis.

The Board is of the view that Alliance's SCADA system would reduce the possibility of events with combinations of pressure and temperature occurring which would exceed the designed fracture arrest conditions.

Further, the Board notes that a number of factors would have to occur simultaneously to contribute to an event which would lead to a propagating fracture under conditions exceeding the design conditions for fracture arrest. First, a fracture would have to be initiated under conditions which are not conducive to fracture initiation (per section 5.3.5 on fracture initiation control); second, the downstream compressor would have to be shut down; and third, the pressure/temperature conditions would have to develop along the pipeline which would exceed the fracture arrest design conditions. The Board is of the view that the possibility of such an event is remote.

The Board is of the view that the onus is on Alliance to ensure that the pipeline is operated within the design range for fracture arrest.

5.3.7 Fracture Propagation Control

5.3.7.1 The Battelle Two-Curve Method

It was generally recognized during the hearing that the design of the Alliance Pipeline is outside the range of the ductile fracture propagation control criteria of CSA Z662-96. Therefore, Alliance resorted to the use of the "Battelle two-curve" method for determination of the arrest conditions for ductile fracture propagation.

The method is illustrated conceptually by Figure 5-1. The lower curve represents the gas decompression velocity and the upper curve represents the fracture velocity, both as a function of the pressure inside the pipeline.

When a fracture is initiated in a pressurized pipeline and starts propagating, it is driven by the internal pressure. As a result of the fracture, the original internal pressure starts decreasing with the velocity of the decompression wave which is moving in the same direction as the propagating fracture. If the decompression wave moves faster than the propagating fracture, the fracture starts to lose the driving force and arrests.

The decompression wave velocity curve for methane is a smooth curve which can be determined analytically or experimentally in a separate decompression experiment. On the other hand, rich natural gas decomposes during decompression into two phases, which demonstrates itself in a plateau within the decompression curve. This has the effect of slowing down the decompression wave velocity so that a high pressure exists longer at the fracture tip than would be the case for the decompression of pure methane. This longer duration of high pressure necessitates a higher fracture toughness for the arrest of a propagating fracture.

The velocity of a propagating fracture is a function of the stress in the pipe wall, the pipe size, and the pipe's resistance to ductile fracture propagation. The fracture velocity curve is determined by using an equation derived empirically from pipe burst tests.

If the fracture velocity curve is above the gas decompression velocity curve in the Battelle two-curve diagram, this indicates that the fracture would stop within one or two pipe joints. In other words, the gas decompression wave quickly "outruns" the fracture, thus removing the driving force at the crack tip. At the toughness level where the curves are tangent, a fracture has just enough driving force to propagate long distances. The toughness must therefore be increased above this level to ensure fracture arrest.

Figure 5-1
Battelle Two-Curve Method

5.3.7.2 Determination of Fracture Toughness

Fracture propagation resistance is provided by the pipe material's fracture toughness, which is measured by the absorbed energy required to break a laboratory test specimen (expressed in joules ("J")). In addition to the absorbed energy, the percentage of shear area of the fractured surface is also measured to express the ductility of the material.

The CVN test is most often employed to measure the fracture toughness and involves a small dimensionally-standardized specimen with a machined V-shaped notch from which the crack is initiated. Another test that is sometimes used is the DWTT, which involves the breaking of larger-size specimens that have the full wall thickness of the line pipe.

In many cases, the CVN test has proven to be of high value due to its low cost and good correlation with full-scale fracture behaviour. It has been recognized since the late 1970s, however, that the established correlation between CVN toughness and resistance against full-scale fracture propagation (based on the Battelle two-curve analysis) starts to break down for steels with CVN energies above 100 J. These steels are so tough that a high proportion of the CVN energy is used on deformation of the test specimen and crack initiation from the notch. The analysis therefore provides less information on the resistance against fracture propagation with increasing toughness of the steel. In other words, CVN values above 100 J obtained from the Battelle two-curve analysis under-predict the full-scale dynamic fracture resistance of the pipe.

Therefore, CVN energy determined from the Battelle two-curve analysis must be increased to become representative of the toughness required for fracture arrest. The magnitude of this increase must be based on correlation with full-scale burst test results.

There is a pool of full-scale burst test results in the literature which provide CVN absorbed energy values applicable to the simulated design and operating parameters. In cases where the specified parameters are beyond the envelope of past tests, representative new full-scale burst tests are typically performed so as to validate the design and at the same time expand the envelope. For example, Foothills conducted a testing program at its Northern Alberta Burst Test facility in the early 1980s to simulate the parameters applicable to its Alaska Highway Pipeline Project.[1] From these tests, Foothills determined a correction factor of 1.3.

5.3.7.3 Alliance's Design

For the purpose of fracture propagation control, the Alliance Pipeline design involved the following three considerations: (i) ensuring that the line pipe specified would exhibit ductile properties at the minimum design temperature of the pipeline; (ii) determining the minimum design temperature for measuring notch toughness; and (iii) determining the minimum toughness required to arrest propagating ductile fracture for the Alliance Pipeline operating conditions.

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[1] The Canadian portion of the Alaska Natural Gas Transportation System, which is also referred to as the Alaska Highway Pipeline Project, was certificated in 1978 by the Parliament of Canada through the passage of the *Northern Pipeline Act*. Only the southernmost portion of the pipeline in Canada (referred to as the Foothills Prebuild) has been constructed to date.

As noted in section 5.3.4, the minimum design temperature was determined by Alliance to be -5 °C. The Company specified a minimum AHA of 85 per cent shear area in the DWTT at -5 °C to ensure that the pipe would be in the ductile region under any operating conditions.

In applying the Battelle two-curve method, Alliance used a decompression wave velocity curve developed by Clearstone Engineering for three design gas compositions, the maximum operating pressure, and the corresponding operating temperature. As shown by Figure 5-1, the curve for the ultimate rich gas mixture has a plateau at about 6 200 kPa, indicating that liquid particles begin to form at this point in the decompression. This has the effect of producing a sustained pressure for a longer period at about 6 200 kPa, which would require high fracture toughness for arrest. The fracture velocity curve was calculated using the "duct tough" spreadsheet. For the 914 mm diameter, 14.2 mm wall thickness, grade 483, and ultimate rich gas case, the fracture velocity curve for 149 J CVN energy is tangent to the gas decompression curve, representing a transitional point between propagating and arresting fracture ranges. Since this CVN energy value is over 100 J, a correction factor had to be applied.

Dr. B.N. Leis of the Battelle Memorial Institute was commissioned to develop corrections to the two-curve Battelle model for the Alliance Pipeline. These corrections were presented in a June 1997 report entitled "Relationship Between Apparent (Total) Charpy V-Notch Toughness and the Corresponding Dynamic Crack-Propagation Resistance".[1]

In developing the corrections, Dr. Leis assessed the energy area under the force-displacement curves obtained for eight instrumented Charpy tests for eight different materials. In each case, he divided the energy into (i) deformation energy, (ii) fracture initiation energy, and (iii) fracture propagation energy so as to obtain the energy available for crack arrest and to ensure that the specified CVN value would contain the necessary fracture arrest component.

For the 914 mm diameter section of mainline, Alliance utilized a correction factor of 1.21 based on Dr. Leis's analysis. The corrected CVN energy for arrest is 149 J times 1.21, or 181 J.

If the minimum CVN energy value for a pipe order were to exceed this value, then all pipe lengths would have energy levels adequate for fracture arrest. Alternatively, if this CVN energy was specified as an AHA, approximately 50 per cent of the lengths would have the ability to arrest a fracture. Alliance chose to specify 195 J for the 914 mm diameter section of the mainline as the AHA CVN energy value. Alliance also specified the minimum CVN absorbed energy for any heat as 136 J. After discussing these specifications with a potential supplier of helically formed pipe, Alliance received assurance that the AHA fracture toughness specification could be raised to 280 J.

Alliance followed the same procedure for determining the fracture toughness requirements for the 1067 mm diameter section of the mainline and obtained a corrected CVN energy value of 208 J (calculated as 168 J from the two-curve diagram times a Leis correction factor of 1.24).
The Company chose to specify an AHA CVN energy value of 215 J.

Alliance intends to use the 280 J pipe for the construction of the 914 mm diameter mainline, which is significantly higher than the calculated fracture arrest toughness of 181 J. Although the fracture

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[1] An addendum to the Leis report (dated 11 November 1997) was also placed on the hearing record.

driving force for the 1067 mm diameter mainline is higher than that for the 914 mm diameter mainline, Alliance specified 215 J, which is marginally higher than the calculated value for fracture arrest of 208 J.

The most severe operating conditions and the fracture toughness specified for these conditions are shown in Table 5-2. Alliance also calculated fracture toughness for less severe operating conditions, leaner gas compositions, and thicker-wall pipe. All these combinations require lower fracture toughness than those calculated for the most severe conditions.

Table 5-2
Data for Alliance Operating Conditions and Fracture Toughness Requirements

Pipe Specification	Stress Level	Discharge Conditions		Gas Comp.	Calculated CVN Energy		Specified CVN Energy		Pipe forming process	CVN test temp.
	% SMYS	Pressure kPa	Temp °C	MJ/m^3	Battelle 2-curve (J)	Leis Corrected (J)	Minimum (J)	AHA (J)		°C
914 mm x 14.23 mm, Grade 483	80	12000	24	Ultimate Rich 44.33	149	181	136	195	U and O	-5
							181	280	helical	
1067 mm x 11.43 mm, Grade 483	80	8274	4	Ultimate Rich 44.33	168	208	160	215	helical U and O	-5

Alliance also assessed and specified fracture toughness requirement for components and for the line pipe seam weld. A minimum CVN absorbed energy of 36 J was specified for the seam weld.

Alliance proceeded to calculate the expected fracture length for the 914 mm diameter section by assuming that the fracture toughness for a pipe order would be normally distributed and the pipe lengths would be randomly distributed in the pipeline. Under these assumptions, the ductile fracture would arrest within 14 pipe lengths or 168 m using the ultimate rich gas composition. Alliance repeatedly emphasized that the fracture control design determined for the most severe operating conditions and ultimate rich gas would provide a wide range of safety for less severe operating conditions and leaner gas compositions.

5.3.7.4 Full-Scale Burst Test Program

Alliance initially contended that its fracture propagation control design for the 914 and 1067 mm diameter sections of mainline was fully validated on the basis of existing burst test data. However, during the hearing and following challenges of its fracture arrest design, Alliance committed to a full-scale burst test program for 914 mm diameter pipe.

The test program is intended to validate both the specified CVN energy value for fracture propagation arrest and the Leis correction model. Up to three tests were planned to be conducted between August and December 1998 at the Spadeadam test site in Cumbria, England using 914 mm diameter line pipe produced by the steel mills which will be supplying the pipe for the Project.

Alliance noted that, at the ultimate rich gas composition and at maximum operating pressure, the 1067 mm diameter mainline would experience a higher driving force than the 914 mm diameter mainline. The Company advised of its intent to perform an adjustment in conditions on one of the 914 mm diameter line tests in order to simulate this higher level of driving force and to allow the fracture arrest design for the 1067 mm diameter mainline to be verified without physically testing the larger-diameter pipe.

Alliance committed to review and, if necessary, to revise its fracture prevention and control plan based on the results of the first two burst tests. Given the testing schedule, Alliance indicated that the confirmed or revised plan could be submitted to the Board well in advance of field construction.

Each burst test would involve an approximate 100 m long test section comprising nine pipes of various notch toughness values commencing with the initiation pipe of very low toughness. The fracture would be initiated by an explosive charge placed in the middle of the initiation pipe. The fracture would propagate in the pipes of increasing fracture toughness. The toughness of the pipe where arrest occurs would represent the notch toughness which would be required for arrest in the proposed pipeline. With these tests, Alliance hoped to (i) demonstrate that the CVN toughness of the selected pipe material is sufficient for fracture arrest and (ii) validate its fracture propagation prevention and control design including the Leis analysis.

Alliance planned to install crack arrestors at both ends of the test section as an added precaution and to test a specific arrestor design.

5.3.7.5 Crack Arrestors and Operating Limits

Alliance stated that, in the unexpected event that none of the pipe in the full-scale test sections arrested the propagating fractures, crack arrestors would be installed on the pipeline in accordance with Clause 5.2.2.3 of CSA Z662.

Crack arrestors are mechanical means of arresting a propagating fracture which typically consist of bands of steel wrapped around the pipeline or thicker-wall sections of pipe placed at intervals along the pipeline. As a propagating fracture passes into an arrestor, the fracture driving force is reduced below the fracture resistance of the arrestor and the fracture stops.

The crack arrestors would become the primary method of providing positive control of fracture propagation; however, the pipe would still be purchased as originally specified to maintain the very high level of crack initiation resistance achieved.

A preliminary consideration of crack arrestors in the Alliance fracture propagation control design calls for their installation approximately every 350 m. The spacings might vary in the vicinity of dwellings and in other circumstances such as in the vicinity of significant roadways.

Alliance submitted that its fracture propagation arrest design is already validated on the basis of existing burst test data for gas compositions having a gross heating value up to 42.5 MJ/m^3 (1138 Btu/scf) at the highest intended MOP of 12 000 kPa. The Company therefore argued that the pipeline could be safely operated at those levels pending successful burst tests. The Company also noted that the gas actually expected to be transported on the pipeline would have a gross heating value of approximately 40.0 MJ/m^3 (1072 Btu/scf), showing the conservatism inherent in the design.

Views of Intervenors

Duke, IPLE, and WEI argued in support of Alliance's fracture propagation control design, including the proposed full-scale burst test program. On the other hand, and as explained in the following text, TCPL and Foothills were critical of the design. Cochin commented in final argument that it would be appropriate for the Board to impose a condition requiring validation of the design by full-scale burst tests.

TCPL argued that the Leis analysis is flawed and provides no reliable guidance in determining the fracture toughness required to arrest a propagating fracture under the extreme conditions represented by the Alliance proposal. TCPL's specific criticism was as follows:

(i) The correlation set out in the study by Dr. Leis did not account for the effects of two-phase gas decompression and is, in TCPL's view, not applicable to steels exhibiting rising upper shelf behaviour.[1] With respect to the former, Dr. Leis applied the correction factor to the existing full-scale burst test data available in the literature which was predominantly obtained from tests with air and other single-phase decompression gases. Only a limited amount of two-phase decompression data was available.

(ii) The analysis wrongly assumed a constant pendulum velocity during the Charpy tests performed by Dr. Leis.

(iii) Dr. Leis derived his equation for determination of the correction factor on the basis of only a few valid data points and was not able to produce the data for the purpose of replication. Two of his eight tests were invalidated by the Charpy machine not having enough energy to break the specimens and three others were below the 100 J limit for the proposed correction. This left three points on which to base the correction correlation.

(iv) There were calibration errors during the entire test program.

TCPL also submitted that Dr. Leis's correction does not reflect material or Charpy test characteristics and therefore does not represent a reliable procedure for using Charpy tests for pipeline fracture arrest predictions. TCPL suggested that more reliable test methods are available to predict the fracture resistance, such as the static pre-cracked DWTT ("SPC DWTT"). The specimen used in this test provides better dimensional similarity to the pipeline wall than the CVN specimen, and the SPC DWTT absorbed energy is predominantly energy used for crack propagation. TCPL claimed that this method was used on Japanese pipe and that a good correlation was obtained between predicted fracture velocity and the actual fracture velocity measured in full-scale burst tests.

TCPL completed a testing program on the 280 J AHA helical pipe steel that Alliance proposes to use for its 914 mm diameter mainline. This testing program generated correlations between Charpy toughness values and the SPC DWTT values. In TCPL's view, the results of this correlation illustrate the lack of reliability of Leis's prediction that arrest will occur at 181 J for the 914 mm diameter mainline and 208 J for the 1067 mm diameter mainline. TCPL could not predict, on the basis of this program, whether the 280 J pipe would be able to arrest the fracture in a 914 mm diameter pipe full-

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[1] Rising upper shelf behaviour is exhibited by heavily controlled rolled, low alloy, high strength steels.

scale burst test, but was confident in predicting that the fracture would not arrest in a 1067 mm diameter pipe full-scale burst test.

TCPL also commented on Alliance's full-scale burst test program. One aspect highlighted by TCPL is that Alliance is not planning to test the case that has the highest crack driving force. TCPL observed that the combination of higher crack driving force and the lower toughness at +4 °C makes the 1067 mm diameter line the more critical one from a fracture control viewpoint (i.e. versus the 914 mm diameter case). As an alternative to physically testing both 914 mm and 1067 mm diameter pipe, TCPL suggested that Alliance could perform tests solely on the 914 mm diameter pipe provided that both of the following conditions are met:

(i) The temperature, or pressure, or a combination of both is adjusted to represent the higher fracture propagation driving force of the 1067 mm diameter design. In this respect, if the 914 mm diameter pipe test is conducted at 12 000 kPa, the test temperature would need to be +16°C. Alternatively, if the 914 mm diameter pipe test is conducted at +24 °C, the initial test pressure would need to be 12 210 kPa.

(ii) The Leis CVN-based method of predicting fracture resistance requirements would need to be abandoned in favour of a method which is capable of accommodating manufacturer-specific properties in full-thickness fracture propagation resistance behaviour as a function of the test temperature. TCPL recommended the use of full-thickness tests such as the SPC DWWT, chevron-notch DWTT, or crack-tip-opening angle specimens to supplement standard CVN testing.

In relation to crack arrestor validation, TCPL observed that the proposed burst tests involve having the crack arrestor on the highest toughness pipe. In TCPL's view, the arrestor should be scaled up to work on the lower toughness pipe where the crack driving force which the arrestor needs to overcome is higher.

TCPL also questioned the appropriateness of utilizing crack arrestors as a primary means of controlling propagating fractures in the event that full-scale burst tests are unable to validate Alliance's design. Furthermore, TCPL submitted that it would not be prudent for Alliance to operate on the basis of its proposed interim operating parameters prior to the completion of full-scale burst testing.

Foothills also made submissions on Alliance's fracture propagation control design, and in particular on Dr. Leis's analysis and on Alliance's proposed full-scale burst test program.

With respect to the former, Foothills was not convinced of the validity of the Leis correction method and the data to support it. To support its view, Foothills analyzed the data of all eight instrumented CVN tests conducted by Dr. Leis and concluded that the data was unreliable. Since this data was used to derive the equation for the correction factor and for the prediction of the required CVN absorbed energy for the fracture arrest in the Alliance Pipeline, Foothills considered that Alliance's fracture arrest prediction was also unreliable.

Foothills explained that it performed full-scale burst tests for its Alaska Highway Pipeline Project directly involving the relevant combination of gas composition and the pressure and temperature range. On the basis of these project-specific tests, a 1.3 correction factor was empirically determined by Foothills

Foothills applied the Leis correction method to the parameters applicable to its own project and obtained correction factors between 1.18 and 1.24, which under-predict the Foothills full-scale burst test results. Foothills did not consider that even the correction factor of 1.3 could be confidently applied to Alliance's design conditions. According to Foothills, the limited experimental data available for the conditions most closely approximating the parameters for Alliance's 914 mm diameter mainline design indicates that the correction factor for these full-scale burst test are 1.66 and 1.82. Foothills concluded that Alliance would have to validate its pipeline design by full-scale burst tests specific to the design conditions and the project pipe.

Based on its experience with full-scale burst tests and the evaluation of the testing results, Foothills was of the opinion that the limited Alliance test program would not produce a validation for the Leis correction method. The Alliance full-scale test program would provide empirical validation of the fracture arrest toughness for the conditions tested.

Foothills also commented on the applicability of the 914 mm diameter full-scale tests for the validation of the 1067 mm diameter fracture arrest design. Foothills was of the view that the 1067 mm diameter fracture arrest design could be potentially addressed by conducting one or more 914 mm diameter tests under more severe conditions (e.g. by reducing the test temperature). This could provide a reasonable basis for the determination of modified arrest criteria for the 1067 mm diameter pipeline design. The other options were: (i) to conduct 1067 mm diameter full-scale burst tests under operating conditions, (ii) to modify the fracture length design criteria, (iii) to modify the operating conditions, or (iv) to utilize crack arrestors.

Foothills suggested that Alliance might consider additional types of small-scale laboratory testing on full-thickness specimens such as instrumented and/or alternative notched DWTT or crack-tip-opening angle test specimens to provide a wider range of alternative solutions.

Foothills also argued that Alliance's suggested interim operating limits are not within the envelope for which unequivocal evidence of arrest based on pipe toughness has been achieved. Foothills submitted that, pending successful full-scale burst testing, the gas composition should be limited to a C_{2+} content of about 4.5 per cent or, alternatively, a gross heating value of about 49.3 MJ/m^3 (1050 Btu/scf). Foothills also submitted that, for a gas composition having a gross heating value of 42.5 MJ/m^3 (1138 Btu/scf), the MOP should be limited to that for which pipe body arrest has been demonstrated in full-scale tests for the same composition, namely 8 687 kPa (1260 psi).

Applicant's Reply to Intervenor Submissions

Alliance defended its ductile fracture propagation control design during cross-examination, in written filings, and in final argument. Following are some of the points raised by the Company in reply to the submissions made by TCPL and Foothills:

(i) Alliance suggested that the participation by TCPL and Foothills on the fracture prevention and control issue was not solely motivated by concerns of safety or public interest but, rather, by concerns of competition from a new more efficient pipeline. The Company further suggested that TCPL and Foothills were applying double standards through certain of their criticisms.

(ii) The Company noted that the issue of fracture propagation control is clearly a complex one, subject to a great deal of engineering judgement. The Company went on to state that it had assembled a team of world-renowned experts to assist in the development of its fracture prevention and control program and, moreover, that the program was endorsed through a peer review by certain of its owners who are experienced pipeline companies.

(iii) Alliance noted that, prior to the work of Dr. Leis, the industry tended to use a flat 30 per cent correction to CVN energy values determined from the Battelle two-curve method when considering designs requiring high toughness. The Company maintained that the Leis correction factor is appropriate and constitutes a conceptual advance over the flat 30 per cent "gross-up" because: (1) it has been developed based on tests designed to separate the energy available to resist propagation from the total measured CVN energy; (2) it has been validated by comparison to the universe of burst test data, both for rich gas and otherwise; and (3) it is consistent with the results of Foothills' Northern Alberta Burst Tests, which is particularly significant given that these tests represent fracture driving forces reasonably similar to those that Alliance has calculated for its system.

(iv) Alliance acknowledged that Dr. Leis assumed constant velocity of the hammer in the CVN test, but went on to note that, in developing his correction, Dr. Leis addressed this concern by excluding energy associated with the significant effects of decreasing velocity in calculating integrated energy.

(v) For the following reasons, Alliance disagreed with TCPL's assertion that the SPC DWTT is a more appropriate means than CVN testing for assessing toughness and general arrestability of pipe: (1) the SPC DWTT induces large amounts of cold work into the steel in the pre-cracking through which the fracture subsequently runs in breaking the specimen; (2) the cold work lowers the toughness of the steel and increases the transition temperature; (3) current Battelle research shows that the SPC DWTT specimen does not usually continue to crack along the pre-cracked plane when impact tested but, rather, that the crack reinitiates on different crack planes in many cases, further undermining any logical appeal this test might have had; and (4) the test is not a standardized test and was rejected when proposed for American Petroleum Institute standardization in 1979. Alliance also noted that the correlation of prediction based on the SPC DWTT has not been validated with the existing full-scale burst test data base as has the CVN toughness measurement with the predicted toughnesses using the Battelle two-curve method and Leis correction factor.

(vi) The Company argued that, regardless of the detailed concerns in relation to the fracture control design, the required minimum and AHA toughness specifications for the whole Alliance system, and particularly the 914 mm diameter portion of mainline, are very conservative.

(vii) Furthermore, regardless of the conservatism inherent in the Alliance Pipeline design, a full-scale burst testing program will be carried out to validate the Leis correction model and to clearly demonstrate the ability of the pipe to arrest propagating fractures.

Views of the Board

The Board considers, rhetoric aside, that there was a constructive debate during the GH-3-97 proceeding on the appropriate fracture prevention and control design for the Alliance Pipeline.

The Board notes that the recognized experts who participated in the hearing did not fully agree on the approaches that would lead to a safe design for ductile fracture propagation arrest. The Board observed that this issue evolved over the course of the hearing and resulted in Alliance undertaking to simulate the operating conditions for the proposed mainline pipe in full-scale burst tests prior to the commencement of construction. The Board notes that there was final consensus among the hearing participants that full-scale burst testing would be the most appropriate means of validating the selected design.

The Board is satisfied that Alliance included the full-scale burst testing of 914 mm diameter pipe at the proposed MOP in the fracture prevention and control plan. The full-scale burst test results will be used to validate the ductile fracture propagation control design for the 914 mm diameter mainline and smaller-diameter lateral lines with lower fracture driving force.

Given the particulars of the burst test program, the use of the Leis correction model is of no practical concern for the 914 mm diameter mainline. The use of the model is, however, of concern with respect to the 1067 mm diameter mainline.

The Board is of the view that the 1067 mm diameter mainline, which is characterized by a fracture driving force higher than for the 914 mm diameter mainline, would ideally be validated by a full-scale burst test program performed on that pipe. The Board is also of the view that, if such a burst test program is impractical, Alliance may use the burst test program for 914 mm diameter pipe to simulate the equivalent fracture driving force of the 1067 mm diameter mainline by lowering the test temperature or increasing the test pressure or both. The Board further considers that Alliance should establish the equivalent fracture driving force based on full-thickness tests, such as the SPC DWTT, in addition to CVN tests.

Any certificate issued would include a condition requiring Alliance to file a detailed report on the results of the above testing with the Board for approval at least 30 days prior to the commencement of mainline trenching. The condition would further stipulate that, in the event that the tests are unsuccessful, Alliance shall submit operating limits or a crack arrestor program, with or without operating limits, for either or both of the 914 mm and 1067 mm diameter sections of mainline, together with technical justification, for approval by the Board.

Chapter 6

Traffic, Tolls, & Tariffs and Method of Regulation

6.1 Traffic, Tolls, & Tariffs

Views of the Applicant

Alliance stated that it had designed a transportation service package that satisfied the needs of the shippers, owners, and lenders associated with the Project. In the Company's view, the transportation service package will provide both toll certainty and toll stability for its shippers, and adequate revenue to satisfy investor and lender requirements.

Alliance argued that all of its shippers are treated equally, and that all have the same rights, privileges, and obligations. The Company noted that 37 shippers have contracted for 98 per cent of the pipeline's capacity for a term of 15 years, that the transportation service package was freely negotiated by shippers, and that no shipper sought changes to the tariff. The Company contended that the tolls are just and reasonable and that there is no discrimination.

Alliance explained that the toll consists of a demand charge, which is essentially a reservation charge for the right to transport gas, a commodity charge for volumes actually transported, and an in-kind charge for fuel. In addition, there is a surcharge for contracted capacity on the Taylor-Aitken Creek portion of the pipeline to reflect the extra distance that the gas must be shipped. Under the terms of the pro forma Transportation Service Agreement, shippers would commit to paying demand charges for the first 15 years of service.

Alliance stated that the pipeline has 44 receipt points in Canada and only one delivery point in the United States, at Joliet, near Chicago, Illinois. Apart from the surcharge to be levied on shippers on the Taylor-Aitken Creek portion of the pipeline, there will be only one toll for service to Joliet.

The tolls would be set on a cost-of-service basis, under which the tolls would reflect the capital and operating costs of the system, plus an allowance for a return on the investment capital. The transportation service package includes a capital efficiency incentive which encourages Alliance to build the Project in a cost-effective manner. The incentive provides for an increase or reduction in the Company's return on equity according to whether actual capital costs are less than or exceed agreed-upon baseline estimates.

The Company also has committed to bear the risk of shipper default on payment, stating that any costs arising from default would be borne by the owners as opposed to being spread among the remaining shippers.

Alliance has proposed a volumetric tolling system under which shippers would be billed according to the volumetric capacity which they have contracted on the system. The Company argued that the costs of shipping gas on its system would vary with the volumes of gas transported, and not with the heat content of the gas. In Alliance's submission, the unique design of the pipeline will allow the

Company to carry dense phase gas without incurring any increase in transmission costs. On that basis, Alliance argued that a volumetric toll would be most consistent with the principle that tolls should be cost-based.

In response to suggestions by intervenors that thermal-based tolls would be more appropriate, Alliance argued that such tolls would not adhere to the principle of cost causation and submitted that no attempt was made to show that thermal tolls represent a proper allocation of costs. The Company also stated that issues of intra-shipper inequity would be created if different tolls for natural gas of different heating values were charged.

Alliance responded as follows to NOVA Chemicals' submissions relating to the Gas Industry Standards Board ("GISB"). Alliance noted that the GISB is an industry body, and not a regulator, whose recommendations are sometimes adopted by the FERC as guidance in establishing its own rate design policies. Alliance stated that, based on a GISB recommendation, the FERC has determined that the rates charged by gas pipelines under its jurisdiction should be stated (as opposed to calculated) on a heat content basis. In Alliance's view, this policy is simply meant to facilitate a comparison by shippers of the relative transportation costs on the various pipeline systems, and is not intended to shift costs between shippers of rich and lean gas. Alliance also suggested that any plan by TCPL to move to energy-based tolls has no bearing on what is appropriate for the Alliance Pipeline.

The tariff also provides for another service which Alliance has named Authorized Overrun Service ("AOS"). Under AOS, Alliance would allocate all of the spare capacity that exists on the system on any particular day to the firm service shippers according to each shipper's contracted firm service volumes (up to a maximum of ten per cent of each shipper's contracted demand quantity). There will be no charge for moving gas under this service, other than the fuel charge.

Alliance submitted that AOS was an innovative approach to the problems that are created by the fact that available daily capacity on a pipeline system varies considerably. As a result of this variability, most gas pipeline companies carry extra capacity which is marketed daily as interruptible service. The Company stated that AOS will puts maximum control of the available capacity in the hands of the shippers. It noted that, since shippers would be paying for all of the fixed costs of the pipeline through their demand charge payments, they are entitled to all of the pipeline's capacity. Alliance also stated that the transportation rights will be tradeable on a secondary market, thereby providing additional flexibility to the shippers.

In response to some intervenors' arguments that AOS would provide a "free ride" for NGL injection, Alliance argued that removal of this benefit would interfere significantly with the commercial arrangements agreed to between Alliance and its shippers, owners, and lenders.

Alliance also noted that if firm shippers do not fully utilize AOS, the excess capacity will be marketed as interruptible service. The interruptible service toll is would be 100 per cent of the firm service demand and commodity tolls, plus in-kind fuel, and additional revenues from interruptible service would be refunded to firm service shippers in the next billing period.

Finally, the proposed tariff requires that shippers relinquish to Alliance the rights to any liquids entrained in the gas streams delivered to the pipeline. As compensation for any liquids that are extracted, shippers would receive at the U.S. delivery point quantities of natural gas having an equivalent thermal content. Alliance noted that shippers are not required to deliver liquids to the pipeline and stated that the pipeline's design provides shippers with increased options for marketing their liquids.

Views of Intervenors

The concerns that intervenors expressed about Alliance's proposed tariff were summarized in section 3.3 of these Reasons. In brief, a number of parties objected to various aspects of Alliance's proposed transportation service package because they were concerned that some provisions could distort the operation of a competitive market in Alberta for NGLs, in particular ethane. Although these parties requested that the Board disallow certain provisions of Alliance's tariff, for the most part, their concerns related to the potential impacts on the Alberta petrochemical industry rather than on the justness and reasonableness of the proposed tolls per se.

NOVA Chemicals and the CCPA stated that Alliance will transport both lean natural gas and NGLs. The CCPA argued that these commodities constitute different "traffic" within the meaning of section 62 of the *NEB Act* and that it would be unjust and unreasonable to charge the same toll for transporting different types of traffic. It was also argued that Alliance would be providing a bundled service that would be discriminatory, since shippers would not be allowed to maintain ownership of their liquids unless they also happen to be owners.

NOVA Chemicals and the CCPA argued that a volumetric toll would result in cross-subsidization of the transport of NGLs by the transport of natural gas because NGLs would get a free ride while lean gas would bear the cost. Several intervenors argued that thermal tolls would be preferable to volumetric tolls. The CCPA argued that thermal tolls would reflect the value of the service provided, recover a fair proportion of the costs incurred in transportation, and avoid cross-subsidies between different streams. Further, it was argued that the proposed AOS would be unfair because it would provide a service at almost no cost.

NOVA Chemicals stated that, in the U.S., the use of energy or thermal units in contracts has been well established for many years and is accepted as the appropriate and necessary methodology. NOVA Chemicals also noted that the FERC had denied a request by Alliance Pipeline L.P. for a waiver from having to state its rates in thermal units.[1] In the Canadian context, NOVA Chemicals noted that the Canadian GISB Implementation Group has recommended a process for implementation of GISB standards (including thermal tolls) on Canadian pipelines, and that TCPL had already obtained NEB approval to make a conversion to a thermal basis effective 1 November 1998.

As noted in section 3.3, ANG argued that the provisions of the Alliance pro forma Precedent Agreement and Transportation Service Agreement respecting liquids discriminate between owner-shippers and other shippers.

Views of the Board

Pursuant to sections 62 and 67 of the *NEB Act*, the Board must ensure that Alliance's tolls are just and reasonable, and that there is no unjust discrimination in tolls, service, or facilities.

[1] The GH-3-98 hearing record indicated that Alliance Pipeline L.P. applied to the FERC for a re-hearing on this issue.

The Board notes that the tariff and resultant tolls were negotiated between Alliance and its shippers, and that none of the shippers objected to the proposed toll methodology. Furthermore, pursuant to the proposed toll methodology, shippers have agreed to pay demand charges amounting to some $8.2 billion over the first 15 years of the pipeline's operation (including for the U.S. segment of the pipeline). The Board considers this strong evidence that the shippers are satisfied with the proposed tariff and tolling methodology.

Given the cost-of-service nature of the Alliance Pipeline, the Board considers that the toll methodology should reflect the principle of cost causation. The Board finds that Alliance's proposed volumetric tolling methodology best respects the principle that tolls should reflect the cost of the service provided. As noted in section 5.1.2, the evidence indicates that transportation costs on Alliance will not increase with the heat content of the gas being transported; therefore, in this case, thermal tolls would depart from the principle of cost causation.

The Board also finds the proposed AOS to be an innovative approach to dealing with the variability of available capacity on a natural gas pipeline. By putting control over available capacity in the hands of the shippers, the proposed AOS removes a potential conflict between the pipeline's owners and the shippers over the right to earn additional revenue from unused capacity.

The Board also notes that none of the shippers objected to the tariff provisions which require them to relinquish their ownership of liquids delivered to the Alliance system. The tariff does not require shippers to deliver liquids to the system; the design of the Alliance Pipeline does, however, provide shippers with another option for marketing their liquids.

The proposed tariff and tolling methodology will provide many unique advantages to shippers, and will diversify the service offerings available to shippers on Canadian natural gas transportation systems. The tolling methodology provides long-term certainty and stability for shippers, while AOS maximizes the control by shippers over available capacity.

In conclusion, the Board finds that Alliance's proposed tolling methodology would result in tolls that are just and reasonable, and that there would be no unjust discrimination in tolls, service, or facilities.

6.2 Method of Regulation

Views of the Applicant

Alliance applied to be designated as a Group 2 company for purposes of toll and tariff regulation. Alliance argued that the toll structure and toll methodology in the Precedent Agreements were the result of a collaborative effort by Alliance and its shippers to reduce the regulatory costs normally associated with the determination of tolls. Although Alliance does not expect any disputes with its shippers, the Company stated that complaints would be brought before the Board. Alliance argued that the need for active regulatory oversight would be minimal and that the Group 2 method of regulation would be appropriate.

Views of Intervenors

Cochin was of the view that Alliance, as a large gas pipeline, should pay its fair share of Board cost recovery, as do similar large gas pipeline companies.

Foothills submitted that Alliance should not be exempt from the regulatory oversight accorded to similar-sized companies regulated by the Board. NUL also argued that Alliance, as a large gas pipeline, should be regulated as a Group 1 company.

TCPL was opposed to Alliance's application for Group 2 regulation. It maintained that Alliance should be treated as a Group 1 company for cost recovery purposes. In addition, TCPL submitted that Alliance would have an unfair competitive advantage if it did not have to make public its financial information to the same degree as Group 1 companies. The RMEC also argued that Alliance would gain a competitive advantage if it did not have to file similar financial information as its competitors.

> ***Views of the Board***
>
> For administrative purposes, and in accordance with its *Memorandum of Guidance on the Regulation of Group 2 Companies* ("Memorandum of Guidance"), most recently issued on 6 December 1995, the Board categorizes the pipelines that it regulates as Group 1 or Group 2. The larger pipelines, which typically have many shippers and require ongoing financial regulatory monitoring, are designated Group 1. Group 2 pipelines are regulated on a complaint basis and are generally subject to a lower level of regulatory monitoring.
>
> Since the issuance of the initial Memorandum of Guidance in 1985, the distinction between Group 1 and Group 2 companies with respect to reporting requirements has lessened. In the light of negotiated settlements, certain of the Group 1 companies have been relieved from filing certain reports such as Quarterly Surveillance Reports and Performance Measures. These settlements have also led to a sharp drop in the number of Part IV hearings for Group 1 companies.
>
> Although the Memorandum of Guidance does not identify specific criteria for determining Group 1 or Group 2 status, certain factors have been found relevant when making this determination. These include: (i) the size of the facilities, (ii) whether the pipeline transports commodities for third parties, and (iii) whether the pipeline is regulated under traditional cost-of-service methodology.[1]
>
> On the basis of these criteria, the Board has concluded that Alliance should be designated as a Group 1 company. The Alliance Pipeline would be one of the largest under the Board's jurisdiction. It would transport natural gas for a large number of third party shippers and its tolls would be set on a cost-of-service basis. The Board

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[1] These criteria were previously cited in the Joint Public Review Panel Report dated October 1997 on the Sable Gas Project s (at page 67).

has also decided that it would be appropriate to relieve Alliance from the requirement to file Quarterly Surveillance Reports and Performance Measures.

The share of the Board's cost recovery expense that Alliance will be required to pay pursuant to the *National Energy Board Cost Recovery Regulations* is established by the operation of law and the Board has no discretion to exercise in respect of this matter. The Board notes that there is no direct link between the Group 1 or Group 2 designation of a company for regulatory purposes and the classification of a company for cost recovery purposes.

Chapter 7

Disposition

The foregoing chapters constitute our Reasons for Decision in respect of the application heard by the Board in the GH-3-97 proceeding. The Board is satisfied that the proposed Alliance Pipeline Project is and will be required by the present and future public convenience and necessity, provided that the terms and conditions which are outlined in Appendix V are met. Therefore, subject to the approval of the Governor in Council, Alliance will receive a certificate of public convenience and necessity pursuant to Part III of the *NEB Act*. The Board has also issued Order TG-7-98, pursuant to Part IV of the *NEB Act*, respecting Alliance's tolls and tariffs (Appendix VII).

K.W. Vollman
Presiding Member

A. Côté-Verhaaf
Member

C.M. Ozirny
Member

November 1998
Calgary, Alberta

Appendix I

Project Details

The Project would include a number of laterals in northwestern B.C. and northeastern Alberta, along with associated compression and metering facilities. The majority of the receipts would enter the mainline between the Gordondale Station and the Windfall Compressor Station. The first 345 km of the mainline would consist of 1067 mm (42 inch) diameter pipe, designed to operate at a maximum operating pressure of 8 275 kPa (1,200 psi). At the Windfall Compressor Station, the pressure would be increased to 12 000 kPa (1,740 psi) and the size of the mainline pipe downstream of this point would be 914 mm (36 inches) in diameter. A total of seven mainline compressor stations would be located in Canada at approximate 193 km (120 mile) intervals. The mainline compressor stations are proposed to be installed at the locations outlined in Table I-1.

Table I-1
Mainline Compressor Station Particulars

Station No.	Kilometre Post	Station Name/ Province	No. of Units per Station	ISO (MW) per Unit	Estimated Power Line Length
3-A	421.5	Windfall, AB	3 (2 in series & 1 spare)	30	60 m
5-A	628.4	Morinville, AB	1	23	570 m
7-A	818.4	Irma, AB	1	23	8.0 km
9-A	1010.0	Kerrobert, SK	1	23	1.6 km
11-A	1205.7	Loreburn, SK	1	23	4.5 km
13-A	1398.2	Estlin, SK	1	23	14 km
15-A	1589.9	Alameda, SK	1	23	8.0 km

The Gordondale location would mark the beginning of the 1067 mm diameter mainline. A number of laterals would combine at this site. As such, pig receiving and launching facilities, as well as a slug catcher, would be installed at this location. Storage/tankage facilities would also be required at all mainline compressor stations which have filter/scrubbers.

Mainline block valves would be installed at a spacing of approximately 32 km (20 miles). SCADA facilities would be located at each block valve to enable remote monitoring and operation of the block valve and other equipment and instrumentation.

The Alliance lateral system would include pipe sizes from approximately 114 mm to 610 mm (4 to 24 inches) in diameter as illustrated in Table I-2 (reference Figure 1-3 and accompanying legend for geographic context).

The system would include 26 lateral compressor stations, which are designed to allow for varying levels of installed compression in order to facilitate relocation of lateral compression in response to changing shipper receipt location preferences. Lateral valves would be installed at all receipt point locations and mainline tie-in points, and all lateral receipt points would include custody transfer metering. The particulars are provided in Table I-3.

The pipeline would be designed with full pigging capability and an impressed current cathodic protection system, and all line pipe would be mill coated with external fusion bond epoxy coating. Also, Alliance would use internal coating on the mainline and on all laterals 406 mm (16 inches) in diameter and over. The internal coating would enable Alliance to use smaller compressors, and the combination of smaller compressors and the internal coating would result in lower fuel consumption.

Table I-2
Lateral System Pipeline Sizing

Lateral Name	Pipe Segment		Diameter (mm)	MOP (kPa)	Length (km)
	From	To			
Highway	BC 01	BC 02	508	12 000	9.65
Aitken Creek	BC 02	Taylor Junction	508	12 000	131.43
Taylor	BC 03 / BC 04	Taylor Junction	219	8 275	4.89
Boundary Lake	AB 07	AB 05	219	8 275	21.30
Boundary Lake	AB 05	Taylor Junction	324	8 275	29.60
Pouce Coupe	AB 11	Taylor Lateral	168	9 930	0.81
Fort St. John	Taylor Junction	Gordondale Site	610	9 930	75.34
Peace River	AB 10	AB 09	219	9 930	12.00
Peace River	AB 09	AB 14	273	9 930	34.21
Peace River	AB 14	Mainline	273	9 930	0.79
Gordondale W.	AB 13	AB 12	406	8 275	5.09
Gordondale W.	AB 12	Gordondale Site	406	8 275	0.80
Whitburn	AB 15	AB 16	168	8 275	9.17
Whitburn	AB 16	Mainline	324	8 275	0.39
Valhalla North	AB 17	Mainline	114	8 275	0.12
Valhalla S. Con.	AB 20	Mainline	168	8 275	0.10
Spirit River	AB 23	Wembley Comp	406	8 275	19.37
Teepee Creek	AB 21	Wembley Comp	168	10 690	47.19
Hythe	AB 26	AB 24 / AB 26 JNCT	324	8 275	0.56
Hythe	AB 24	AB 24 / AB 26 JNCT	273	8 275	26.50
Hythe	AB 24 / AB 26 JNCT	Wembley Comp	324	8 275	16.24
Wembley Con.	AB 27	Wembley Comp	273	8 275	0.10
Wembley Con.	Wembley Comp.	Mainline	508	8 275	0.10
Elmworth	AB 27A	Mainline	324	9 930	29.97
Wapiti	AB 29	Mainline	168	9 930	6.66
Gold Creek	AB 30	Mainline	219	8 275	0.29
Karr	AB 31	Mainline	219	8 275	1.66
Simonette	AB 32	Mainline	114	8 275	2.24
Ante Creek	AB 34	AB 35	168	8 275	11.18

Lateral Name	Pipe Segment From	Pipe Segment To	Diameter (mm)	MOP (kPa)	Length (km)
Ante Creek	AB 35	Mainline	219	8 275	13.17
Bigstone	AB 37	Mainline	219	9 930	19.55
Fox Creek	AB 40	Mainline	219	9 930	18.23
Kaybob	AB 41	Mainline	406	8 275	4.76
Edson West	AB 43	Edson Lateral	168	9 930	16.29
Kaybob South	AB 45	Edson Lateral	406	9 930	7.86
Edson	AB 44A	AB 44	219	9 930	40.89
Edson	AB 44	Edson West JNCT	406	9 930	8.18
Edson	Edson West JNCT	Kaybob South JNCT	406	9 930	51.48
Edson	Kaybob South JNCT	AB 46	610	8 275	28.90
Edson	AB 46	Mainline	610	8 275	12.50
Two Creeks	AB 38	Mainline	114	8 275	18.62
Carson Creek	AB 47	Mainline	114	13 100	11.77
Whitecourt	AB 48	Mainline	168	12 000	0.34
Paddle River	AB 49	Mainline	168	12 000	2.09
Cherhill	AB 50	Mainline	168	12 000	2.71
Fort Saskatchewan	AB 53 / AB 54	Mainline	273	12 000	1.79

Table I-3
Details of Permanent Lateral Facilities

Station	Location Name for Compressor Stn. or Meter Stn.	Compressor Station Location Name	Meter Station	Compressor Station	Pigging Facilities	Total kW on Site
BC01	Highway		x		x	
BC02	Aitken Creek	Aitken Creek	x	x		4 860
BC03	McMahon		x		x	
BC04	Younger		x			
T. BOOSTER		Taylor Booster		x	x	2 400
AB05	PetroCan Boundary Lake		x		x	
AB07	Rigel Boundary Lake S		x		x	
	Gordondale				x	
AB09	Canrock Fourth Creek		x		x	
AB10	Rigel Josephine		x		x	
AB11	Star Pouce Coupe	Pouce Coupe	x	x		300
AB12	CNRL Pouce Coupe	Pouce Coupe 2	x	x		150
AB13	WC Gordondale		x		x	
AB14	Canrock Gordondale	Canrock	x	x	x	3 140
	AB14 Junction to Mainline				x	
AB15	Suncor Progress		x		*	
AB16	Norcen Progress	Progress	x	(1)	*	1 200
AB17	Can Ab. Valhalla	Valhalla	x	x		150
AB20	Crestar Valhalla	Valhalla 2	x	(1)		300
AB21	Talisman TeePee Creek	TeePee Creek	x	x	*	600
AB23	AEC Sexsmith		x		x	
AB24	AEC Hythe/Brainard	Hythe	x	x	x	600
	Junction of AB24 to AB26 Lateral				x	

Station	Location Name for Compressor Stn. or Meter Stn.	Compressor Station Location Name	Meter Station	Compressor Station	Pigging Facilities	Total kW on Site
AB26	Rigel Knopcik		x		x	
AB27	Crestar Wembley	Wembley	x	x	x	3 140
AB27A	Can. Hunter Elmworth	Elmworth	x	x	x	900
	AB27A Junction to Mainline				x	
AB29	Ulster Wapiti	Wapiti	x	x	*	900
	AB29 Junction to Mainline				*	
AB30	PetroCan Gold Creek	Gold Creek	x	x		750
AB31	Can. Hunter Karr		x		x	
	AB31 Junction to Mainline				x	
AB32	Encal Simonette	Simonette	x	x	*	150
	AB32 Junction to Mainline				*	
AB34	Rio Alto Ante Creek		x		*	
AB35	Rio Alto Waskahigan	Waskahigan	x	x	*	1 200
	AB35 Junction to Mainline				*	
AB36	Petromet Bigstone		x		x	
AB37	Amoco Bigstone	Bigstone		x	x	900
	AB37 Junction to Mainline		x			
AB38	Summit Two Creeks	Two Creeks	x	x		150
Windfall					x	
AB40	PetroCan Kaybob	Kaybob	x	x		1 420
	AB40 Junction to Mainline				x	
AB41	Amoco Kaybob	Kaybob 2	x	x	x	450
	AB41 Junction to Mainline				x	
AB43	Ranger Galloway		x		x	
	Junction of AB43 to Edson Lateral				x	
AB44	Talisman Edson		x		x	
AB44A	Poco Wolf South	Wolf South	x	x	x	600
AB45	Chevron Kaybob South		x		x	
	AB45 Junction to Mainline				x	
AB46	Amoco West Whitecourt	West Whitecourt	x	x	x	5 600
AB47	Mobil Carson Creek	Carson Creek	x	x		600
AB48	PetroCan Whitecourt	Whitecourt	x	x		1 345
AB49	Can-Oxy Paddle River	Paddle River	x	x	*	1 420
	AB49 Junction to Mainline				*	
AB50	Chauvco Cherhill	Cherhill	x	x	*	1 200
	AB50 Junction to Mainline				*	
AB53	Chevron Fort Sask.		x		*	
AB54	Dow Fort Sask.		x		*	
	AB53/54 Junction to Mainline				*	

* Tie-in capabilities so that transportable pigging facilities could be attached for line sizes NPS 4 and NPS 6.
(1) - denotes that a Compressor Station would be necessary at ultimate volumes (but not at design volumes).

Appendix II

List of Issues

The list of issues appearing in Hearing Order GH-3-97 was as follows:

1. The economic feasibility of the proposed Alliance Pipeline Project having regard to, among other things:

    (a) the outlook for the long-term supply of natural gas available to be transported on the proposed pipeline;

    (b) the outlook for the long-term demand for natural gas in the markets proposed to be served by the proposed pipeline; and

    (c) the ability of Alliance to provide competitive transportation services for natural gas and to successfully attract natural gas to its system over the long term.

2. The potential commercial impacts of the proposed Alliance Pipeline Project.

3. The adequacy of the public consultation process.

4. The potential environmental effects and socio-economic effects of the proposed Alliance Pipeline Project, including a consideration of those factors outlined in the Board's scope decision dated 19 June 1997 in respect of the environmental assessment to be conducted pursuant to the *CEAA*.

5. The routing and location of the proposed facilities and the land rights acquisition.

6. The design of the proposed facilities.

7. The terms and conditions to be included in any certificate which may be issued.

8. The proposed toll methodology and tariff.

9. The method of toll and tariff regulation, including the request by Alliance that it be regulated as a Group 2 company (as described in the Board's Memorandum of Guidance dated 6 December 1995 on the Regulation of Group 2 Companies).

Appendix III

Text of Accord

The full text follows of the "Agreement on Natural Gas Pipeline Regulation, Competition and Change to Promote a Competitive Environment and Greater Customer Choice" that was signed on 7 April 1998 by the Canadian Association of Petroleum Producers, NOVA Corporation, NOVA Gas Transmission Ltd., the Small Explorers and Producers Association of Canada, and TransCanada PipeLines Limited.

AGREEMENT ON NATURAL GAS PIPELINE REGULATION, COMPETITION AND CHANGE, TO PROMOTE A COMPETITIVE ENVIRONMENT AND GREATER CUSTOMER CHOICE

BETWEEN:

Canadian Association of Petroleum Producers ("CAPP")

and

NOVA Corporation ("NOVA")

and

NOVA Gas Transmission Ltd. ("NGTL")

and

Small Explorers and Producers Association of Canada ("SEPAC")

and

TransCanada PipeLines Limited ("TCPL")

collectively referred to as the "Parties"

IN RECOGNITION OF the dynamic nature of the Canadian natural gas pipeline industry and the broader interests of all stakeholders therein, the signatories hereto are intent upon promoting a competitive environment and greater customer choice. The Parties also recognize the importance of maintaining their alignment of interest, good communication and a spirit of good faith.

TO THIS END the Parties endorse the following guiding principles:

First, their support for competition and greater customer choice;

Second, the need to construct competitive incremental pipeline capacity from the Western Canadian Sedimentary Basin ("WCSB") by both new competitors and existing pipelines alike in a timely, safe and cost effective manner; and

Third, the need to effect regulatory changes that will provide existing and new pipelines equal opportunity to compete, recognizing that such competition is desirable and in the best interests of all industry stakeholders.

The Parties agree to immediately pursue these guiding principles in the following action areas, and as more fully described within each of the terms and conditions which follow.

1. Competitive Environment

1.01 Competition is a driving force in today's natural gas industry. Our industry and regulatory policies should not only promote and sustain competition, but provide all participants with the equal opportunity to provide greater customer choice, provide incentives for pipelines to build incremental transportation capacity, promote competitive pricing and technological and service innovations, and to make the WCSB an even stronger competitor in North America.

1.02 The Parties agree to support the construction of competitive incremental gas pipeline capacity from the WCSB in a timely, safe and cost effective manner. It is anticipated that new competitive capacity will emerge in this environment.

1.03 The Parties also recognize the need for regulatory changes to provide existing pipelines with the appropriate tools necessary to ensure the competitive environment will function effectively.

2. Interconnection Policy

2.01 The Parties agree that pipeline to pipeline competition may appropriately lead to the creation of additional pipeline capacity and that the duplication of certain facilities can be minimized through the adoption of interconnection policies.

2.02 The purpose of an interconnection policy is to provide shippers with the option of fair and reasonable access to competing transmission systems. Interconnection policies are intended to facilitate the ease of access to markets, the efficient utilization of facilities and involve the following:

a. Pipelines will negotiate in good faith with shippers, the receipt and delivery transportation services and prices to and from points of interconnection (if suitable provisions are not already contained in the tariff). If a pipeline is requesting the transportation service then the pipeline is the shipper. Current transportation services and pricing may be redefined into new service packages (unbundling) as required. Unbundling is not intended to affect existing contractual arrangements, except by mutual agreement by the parties.

b. This interconnection policy shall be reciprocally applied to all interconnecting pipelines.

c. Interconnecting pipelines will enter into an agreement or agreements defining the obligations and commitments of the parties, and filing same with the appropriate regulator upon execution. (The Parties contemplate that in a changed regulatory framework such filing might not be required.)

2.03 Interconnection Agreements provide operationally for the delivery of gas from one pipeline system and the receipt of that gas into the interconnecting pipeline.

a) The interconnecting parties will co-ordinate their facilities to the extent practicable to minimize duplication of facilities. An Interconnection Agreement will define all aspects of the interconnection including, but not limited to:

  i) location(s) of interconnects,
  ii) additional facilities required and ownership,
  iii) operating arrangements for gas flow and exchange,
  iv) volume, quality and composition of gas being exchanged, and
  v) accountability for owning and operating costs of facilities required to effect the interconnection.

b) An Interconnection Agreement must enable pipelines to continue to meet their contractual commitments and service obligations and to maintain their physical and operational integrity and reliability. This would include, but not be limited to, agreement on operational and business transactional procedures such as:

  i) custody transfer metering,
  ii) gas quality monitoring and specifications,
  iii) balancing agreements,
  iv) curtailment provisions,
  v) pipeline operations,
  vi) pressure and flow control,
  vii) reporting of shipper operational information, and
  viii) information delivery mechanisms.

2.04 The price and service terms for the transportation service to or from the interconnect shall be established having regard for such factors as:

  a) the owning and operating costs of the facilities required to effect the transportation service, and

b) the prevailing toll methodology and undue discrimination principles, and relevant market value considerations (as noted above, unbundling of prices and services may be required).

2.05 Other matters to be addressed in either an Interconnection Agreement or transportation agreements with shippers, which impact (either positively or negatively) the operating efficiency of the pipeline systems include, but are not limited to:

a) reduced capacity, reduced compressor efficiency, and/or the need for additional facilities, and

b) differences in gas quality, energy content and composition of the gas being exchanged between the interconnecting pipelines.

2.06 Where agreement cannot be reached, the use of an arbitrated dispute resolution mechanism may be utilized.

2.07 Alternately, or additionally, any party believing this Interconnection Policy is not being complied with through good faith negotiations or who has been unable to reach a satisfactory agreement can take the matter to the appropriate regulator for resolution.

2.08 The Parties agree that this Interconnection Policy is an essential element of a competitive gas transportation infrastructure system and agree to implement this policy in conjunction with the development of a new regulatory framework as agreed to in Section 5 of this Agreement. The Parties agree to the desirability of the adoption of this policy by all pipelines operating out of the WCSB.

3. Unregulated Gas Gathering, Processing, and Marketing Activities

A. Codes of Conduct

3.01 TCPL and NOVA acknowledge industry's concerns with the adequacy of the separation between their regulated gas transportation businesses (the "Regulated Businesses") and their respective non-regulated businesses, such as gas marketing, gas gathering and processing and NGL marketing (the "Non-Regulated Businesses"). Among other issues, industry is concerned with respect to cross-subsidies, information exchanges, asset transfers and preferential or discriminatory treatment between the regulated and non-regulated activities.

3.02 TCPL and NOVA agree to work with CAPP, SEPAC and other industry stakeholders to review their existing codes of conduct and, on a mutually acceptable basis, make the necessary modifications or establish new codes of conduct for dealings between TCPL's and NOVA's respective Regulated Businesses and Non-Regulated Businesses to include the following principles:

a) adequate and effective separation;

b) no preferential treatment nor suggestion of such;

c) timely and equal treatment of all, in respect of:

   i) requests for service,
   ii) access to service,
   iii) provision of service,
   iv) administration of tariffs,
   v) operation of the systems, and
   vi) provision of information (including available capacity and expansion plans);

d) no disclosure of shipper specific confidential information without consent;

e) services provided to affiliates to be on a contractual market based fee-for-service basis and/or regulator approved cost allocation principles;

f) any regulated assets acquired by a Non-Regulated Business from a Regulated Business will be done in accordance with a process approved by the appropriate regulator;

g) employee compliance policy (with recognition of seriousness, timely corrective action including discipline);

h) senior responsible officer;

i) a satisfactory complaint resolution process with appropriate and definitive timelines for the ultimate disposition of the complaint. For example, a Regulated Business shall undertake to respond in writing to each complaint under its Code of Conduct within ten (10) business days;

j) periodic reviews with industry of continuing effectiveness of codes. All requests for review or modification of the codes will be dealt with in a timeframe similar to that established for the complaint resolution process.

3.03 These principles will be reflected in codes of conduct governing the flow of information, assets and/or services from TCPL's and NOVA's Regulated Businesses to their respective Non-Regulated Businesses.

3.04 Nothing herein contained is intended to diminish the ultimate authority of the applicable regulator or the right of any party to seek regulatory review.

3.05 NOVA confirms its intention to divest Pan-Alberta Gas.

B. Netback Steering Committee

3.06 TransCanada Gas Services ("TCGS"), as agent for TransCanada PipeLines Limited, will send a letter to its Netback producers asking for candidates that are willing to serve on a Netback Steering Committee. The producer candidates will decide among themselves an appropriate structure and division of responsibilities. The Committee will, in turn, establish, resource, monitor and provide working guidance to an Audit Subcommittee and a Restructuring Subcommittee. CAPP and SEPAC agree to assist the Netback Steering Committee in finding candidates to serve on both subcommittees, if required.

3.07 The Audit Subcommittee and the Restructuring Subcommittee agree to work with TCGS on a collective and concurrent basis to:

Audit Subcommittee

a) have an historical audit of the TCGS Netback pool conducted by independent auditors. Without limitation to the generality of the foregoing, the Subcommittee will be responsible for negotiation with TCGS of the time frame, terms of reference, scope of the audit and selection of auditors. The Subcommittee will also provide management oversight to the Netback audit.

Agreed upon terms of reference, scope, time frame and estimated costs will be put to ballot for approval by the Netback pool producers.

It is also contemplated that the Subcommittee may manage ongoing reviews and/or audits of the performance of the TCGS Netback pool.

Restructuring Subcommittee

b) engage in good faith discussions with TCGS aimed at restructuring the TCGS Netback pool. CAPP and SEPAC agree to have its representatives and pool producers participate in the Subcommittee. The intent is to determine the feasibility of modifying the existing Netback structure and arrangements to provide improved pricing options to producers, including individually tailored prices, pricing points, pricing terms etc. The new arrangements may also see the elimination of Netback pricing as it is presently calculated, and may provide for physical and financial swaps, and for more delivery options.

One of the areas of responsibility for the Restructuring Subcommittee shall be to work with TCGS to develop a code of conduct governing the operation of the Netback pool business.

As a part of the code of conduct, it is confirmed that TCGS will only engage in the sale of natural gas from the Netback pool to the TCGS margin/trading business in those circumstances where:

i) the sale of natural gas from the Netback pool to the margin/trading business has been specifically identified and is approved by producer ballot;

ii) for administrative or operational reasons the pool supply to balloted markets needs to be sold, at a transparent market transfer price less actual costs incurred, to a TCGS affiliate in order to facilitate the sale of natural gas to a pool market (e.g. sales to an affiliate with DOE and/or FERC import certificates where the gas is to be sold in the United States); and/or

iii) the sale of pool gas was made to a balloted market that is or was subsequently acquired, in whole or in part, by TCGS and/or its affiliates.

4. Merger Benefits

4.01 The Parties recognize an alignment of interests on the expected benefits of the merger of TCPL and NOVA. More specifically:

a. The Parties desire a net benefit to flow to the customers of their respective regulated businesses as a result of the merger.

b. TCPL and NGTL intend to deliver a net benefit to the customers of their respective regulated businesses as a result of the merger.

4.02 The existing incentive settlements in place for TCPL and NGTL provide for the alignment of interests with, among other things, the incentive to deliver cost savings. The Parties understand that the existing incentive settlements and past regulatory decisions provide for:

a. an appropriate mechanism for allocation of the net benefits from the merger between the merged companies' regulated and non-regulated businesses in accordance with accounting policies and practices that have been approved by TCPL's and NGTL's respective regulators;

b. an appropriate sharing mechanism for the net benefits from the merger; and

c. the appropriate accountability.

4.03 TCPL and NGTL will work with their respective industry task forces on:

a. the mechanics to ensure proper matching of costs with benefits, giving consideration to amortizing costs over time;

b. the process to ensure an appropriate allocation of costs and benefits between the customers of TCPL's and NGTL's regulated businesses; and

c. a process for regular reporting on the progress towards the achievement of the net benefits from the merger, with appropriate information on the costs and benefits.

4.04 NOVA will, on behalf of the industry, donate the sum of $1,250,000 for post secondary educational purposes. The specific recipient(s) will be determined by an advisory committee comprising representatives of NOVA, CAPP, and SEPAC.

4.05 In the event that the merger contemplated herein does not, for whatever reason, proceed to conclusion, the sum of $2,000,000 shall be paid by TCPL to benefit the industry in a manner to be determined at such time by mutual agreement of TCPL, CAPP, and SEPAC.

5. Regulatory Change

5.01 The Parties recognize and accept that existing pipelines facing the emergence of actual pipeline to pipeline competition should have appropriate tools by which they also have the flexibility to compete. Therefore the Parties agree that changes in existing regulatory practices will be required and, to that end, agree to negotiate a proposal for a new framework for the regulation of each of NGTL and TCPL, appropriate for an increasingly competitive environment. The Parties recognize and accept that current toll and tariff structures of the AEUB and the NEB do not contemplate the changing risk/reward balance of the emerging competitive environment.

It is acknowledged that these initiatives are of importance to a broad range of stakeholders. Therefore, dialogue with other stakeholders is contemplated.

Such a proposal would then be jointly advocated to all other stakeholders for broad industry acceptance and any necessary regulatory approval(s).

5.02 The Parties agree, with respect to TCPL, that:

a. Details of a term differentiated pricing mechanism will be developed between CAPP and TCPL by May 15, 1998, in which tolls would be linked to contract term with discounts and premiums. Consideration is to be given to incentives for early renewal and the status of existing contracts.

b. The shippers' contract renewal notice period should be changed from 6 months to 12 months (the 1 year minimum term remains the same) and CAPP and TCPL will support the immediate implementation of this change, that is, October 31, 1998 implementation for contracts expiring October 31, 1999.

c. If non-renewals occur during the planned TCPL 1999 expansion resulting (with that expansion) in some uncontracted capacity on the TCPL system, such uncontracted capacity shall be available for discretionary services, (with the associated costs to be included in the firm tolls), and marketed as discretionary service until contracted as longer term firm service.

d. The current expansion shipper filing requirements should be relaxed such that only a minimum 10 year firm transportation contract with appropriate upstream and downstream transportation arrangements will be required, plus an assessment of overall market and supply factors and credit-worthiness. The details of the terms of this relaxation and its implementation shall be developed by May 15, 1998 by CAPP and TCPL.

5.03 The Parties further agree, with respect to NGTL, that:

a. CAPP, SEPAC and NGTL will continue to work together to bring NGTL's products and pricing AEUB filing to a mutually satisfactory resolution, including a review of the 5 year rolling term and receipt point flexibility with necessary amendments to the filing to reflect such mutual agreement. The parties intend this work to be completed by May 8, 1998.

b. If during the first 5 years from the initial coming into service of the Alliance project, underutilization of the NGTL system is caused thereby, the cost of such underutilized capacity will, for that 5 year period, be included in the cost of service and NGTL's rates. This is subject to NGTL, after Alliance has been certificated, making a good faith offer to Alliance with a view to mutually satisfactory arrangements for service on NGTL facilities. NGTL will during the 5 year period use its best efforts to maximize the utilization of its capacity with a view to increasing the volume applicable to the establishment of rates.

5.04 The Parties further agree that they will negotiate by December 31, 1998, a new regulatory framework proposal that recognizes and accepts the inherent risk in providing competitive rates and services. Development of this new regulatory framework proposal will involve key external stakeholders.

5.06 It is recognized and accepted that ultimately the opportunity to exercise flexibility while accepting the inherent risk in providing competitive rates, tolls, or terms of service is a desirable goal. It is recognized that an appropriate degree of regulatory oversight will continue.

6. Support for Merger

6.01 CAPP and SEPAC will support the approvals required to effect the merger between TCPL and NOVA, providing letters of support to the AEUB no later than April 8, 1998, and not to oppose the merger before other regulators and governmental approving authorities.

7. Steering Committee

7.01 Time is of the essence of this Agreement.

7.02 A steering committee initially comprising Barry Jackson, Norm McIntyre, Ted Newall and George Watson will be established to ensure that the intent of this Agreement is implemented in a timely manner.

7.03 All provisions of this Agreement are subject to the operation of law, including but not limited to the decisions of applicable regulators.

IN WITNESS WHEREOF the parties hereto have executed this Agreement this 7th day of April, 1998.

Canadian Association of Petroleum Producers

Per: ______________________

NOVA Corporation and
NOVA Gas Transmission Ltd.

Per: ______________________

Per: ______________________

Small Explorers and Producers Association of Canada

Per: ______________________

Per: ______________________

TransCanada PipeLines Limited

Per: ______________________

Per: ______________________

Appendix IV

Minister's Letter re Environmental Assessment

Attached is a copy of the Minister of the Environment's letter dated 23 November 1998 to the NEB conveying her decision on the course of action to be taken under section 23 of the *CEAA* in respect of the environmental assessment of the Alliance Pipeline Project.

Appendix V

Certificate Terms and Conditions

General

1. Unless the Board otherwise directs, the pipeline facilities in respect of which this certificate is issued shall be the property of and shall be operated by Alliance Pipeline Ltd. ("the Company") on behalf of the Alliance Pipeline Limited Partnership.

2. Unless the Board otherwise directs, the Company shall:

   (a) cause the approved facilities to be designed, manufactured, located, constructed, and installed in accordance with those specifications, drawings, mitigative measures, and other information or data set forth in its application, in its undertakings made to Fisheries and Oceans Canada ("DFO") and Environment Canada, and as otherwise adduced in its evidence before the Board, except as varied in accordance with paragraph (b) hereof; and

   (b) cause no variation to be made to the specifications, drawings, mitigative measures, or other information or data referred to in paragraph (a) without the prior approval of the Board.

3. Unless the Board otherwise directs, the Company shall submit a report to the Board for approval at least 30 days prior to the commencement of mainline trenching which will:

   (a) demonstrate that the ductile fracture propagation control design for the 914 mm diameter mainline has been validated by full-scale burst testing;

   (b) establish the ductile fracture propagation arrest for the materials which will be ordered for the construction of the 1067 mm diameter mainline (i) on a full-thickness basis without using the Leis analysis and (ii) by using the Leis analysis; and

   (c) set out operating limits or a crack arrestor program, with or without operating limits, for either or both of the 914 mm and 1067 mm diameter sections of mainline, together with technical justification, if the tests described in (a) and (b) are unsuccessful.

4. Unless the Board otherwise directs, the Company shall report on its performance in respect of its First Nations and Métis employment and commercial participation objectives for the construction and operation of the Alliance Pipeline. The reports shall be submitted to the Board on a quarterly basis during construction and annually during the first three years of operation.

5. The Company shall adhere to the seasonal timing of construction activities as described in its application or as otherwise adduced in evidence before the Board in the GH-3-97 proceeding. Seasonal times should differentiate between frozen and non-frozen soil conditions.

6. The Company shall:

   (a) except as varied in accordance with paragraph (c) hereof:

      (i) comply with all the timing and setback restrictions as outlined in Appendices A1-13, A1-15, A1-16, and A1-17 of the *Wildlife Assessment, the Alliance Pipeline Project, Volume 2 - Appendices*, dated June 1997;

      (ii) comply with all the timing and setback restrictions, including those outlined for specific species and construction spreads, as identified by Environment Canada in its letters to the Board dated 29 October 1997 and 29 January 1998; and

      (iii) where the Company proposes construction activities within the timing and setback restrictions for locations KP 1388.5 to 1389, KP 1401.5 to 1402.5, and KP 1639 to 1641.5, the Company shall, at least 15 days prior to the commencement of construction for those locations, file correspondence from Environment Canada indicating its views on whether conditions are suitable in those locations for a waiver of the timing and setback restrictions;

   (b) cause no variation to the construction schedule that would result in conflict with the timing and setback restrictions concerning any species protected under the *Migratory Birds Convention Act*;

   (c) for those wildlife species not covered under the *Migratory Birds Convention Act*, cause no variation to the construction schedule that would result in conflict with the timing and setback restrictions without prior approval of the Board; and

   (d) for any variation sought under paragraph (c), submit to the Board, at least 15 days prior to the commencement of construction in locations affected by the timing and setback restrictions, correspondence from Environment Canada and appropriate provincial authorities identifying any previously unaddressed timing and setback restrictions, and indicating their views on whether conditions are suitable in those locations for an amendment of the restrictions

7. Unless the Board otherwise directs, the Company shall ensure that all work and activities associated with temporary facilities are conducted in accordance with provincial and federal fisheries and wildlife setback and timing restrictions

8. The Company shall apply the following criteria for the siting of all temporary facilities including construction camps, pipe and equipment storage, work areas, warehouse areas,

borrow pits, staging areas, new access and other areas that would be used or disturbed prior to or during construction:

(a) avoid native prairie areas and areas that would require clearing of trees by:

(i) using existing cleared sites in forested areas and agricultural fields in agricultural areas, with preference being given to areas currently experiencing industrial use; and

(ii) using sites in areas of native prairie that have been previously cleared of native vegetation and/or altered for industrial use;

(b) avoid Environmentally Significant Areas unless the site already experiences industrial use and its use during construction will prevent the need to create new clearings elsewhere;

(c) avoid areas with known or high potential for wildlife, and significant habitat for wildlife, with a designated status (COSEWIC and provincial), as well as other sensitive/significant wildlife areas;

(d) avoid areas with known or high potential for plants with a designated status;

(e) avoid watercourses and wetlands;

(f) avoid steep slopes, organic soils and poorly drained areas;

(g) avoid areas with known or high potential for heritage resources; and

(h) select sites that will not be in conflict with existing land uses.

9. The Company shall submit to the Board for approval, at least 30 days prior to the disturbance of any proposed temporary facility site that is not in accordance with the criteria noted in Condition 8:

(a) a description of the site;

(b) the environmental effects and measures that would be used to mitigate these effects and, in the event that measures other than those adduced during the hearing are proposed, an analysis supporting the use of these measures; and

(c) the results of consultations with landowners and the relevant municipal, provincial, and federal government departments and agencies.

10. The Company shall submit to the Board and Environment Canada, as soon as available, a copy of the Company's action plan under the federal Voluntary Challenge and Registry Program to deal with greenhouse gas emissions arising directly from the operation of the pipeline.

11. For all watercourse crossings undertaken in winter which would have the potential to impact any sensitive watercourse, the Company shall ensure proper long-term control of erosion and sedimentation through the appropriate use of erosion protection and sediment control measures as described in Table 4-8 of the Comprehensive Study Report.

Prior to the Commencement of Construction

12. Unless the Board otherwise directs, Alliance shall, prior to the commencement of construction, submit an affidavit to the Board confirming that transportation service agreements have been executed for the subscribed capacity.

13. Prior to the filing of the plans, profiles, and books of reference pursuant to section 33 of the *National Energy Board Act*, the Company shall submit to the Board, for approval, notice of any known modifications that require a deviation from the proposed specific route as described in the application. Each filing shall include:

    (a) the results of public consultation, the identity of any affected landowners, and the status of land acquisition (where appropriate);

    (b) an airphoto (where the modification is greater than 50 metres); an environmental issues list identifying all relevant effects of the re-routes on the environment (e.g. soils, vegetation, wildlife, hydrology, and archaeological information); and

    (c) the associated mitigation measures to render those environmental effects insignificant, and in the event that measures other than those adduced during the GH-3-97 proceeding are proposed, an analysis supporting the use of such measures.

14. The Company shall submit to the Board, at least 30 days prior to the commencement of construction of the Alliance Pipeline Project, a construction schedule identifying major construction activities, such as river crossings, and shall notify the Board of any modifications to the schedule as they occur.

15. Unless the Board otherwise directs, the Company shall submit to the Board for approval the construction safety manual required by section 26 of the *Onshore Pipeline Regulations* at least 30 days prior to the commencement of construction.

16. The Company shall provide any comments received from Environment Canada and the British Columbia Ministry of Environment, Lands and Parks ("MELP") on the results of the emissions modelling using the USEPA (1997) ISC3-OLM Model for the Morinville, Estlin, and Taylor Compressor Stations including the need for further modelling or monitoring in respect of these stations.

17. Unless the Board otherwise directs, the Company shall submit to the Board for approval its program for monitoring and reporting COSEWIC listed raptor mortality resulting from the new power lines associated with the Project facilities, the measures that the Company will take to reduce raptor mortality, and the criteria that the Company will use in applying these measures.

18. The Company shall:

    (a) submit to the Board for approval, and to DFO-Habitat, at least 30 days prior to the commencement of construction, a detailed environmental inspection plan for construction identifying the environmental inspectors, their respective qualifications, and their geographic and topical areas of responsibility; and

    (b) notify the Board of any changes to the environmental inspection plan described in paragraph (a), when any such changes are made.

19. The Company shall, at least 30 days prior to the commencement of construction of each construction spread (as identified in the application), submit to the Board, for each previously identified site with a plant species with a designated status and each previously identified significant vegetation community:

    (a) the mitigative option selected for that site (from the list of options provided in the GH-3-97 evidence); and

    (b) a description of the appropriateness of that option based on site-specific conditions and the suitability of the option for the species or community.

20. For any watercourse crossings to be undertaken in winter which would have the potential to impact any sensitive watercourse, the Company shall submit to the Board, at least 15 days prior to commencement of construction of such watercourse crossings:

    (a) a water quality monitoring program to be undertaken immediately prior, during, and after construction of the crossings;

    (b) a contingency plan detailing the criteria for any measures that would be implemented as a result of monitoring undertaken pursuant to paragraph (a); and

    (c) evidence as to whether DFO-Habitat is satisfied with any programs derived pursuant to paragraph (a) and the measures described in paragraph (b).

21. The Company shall submit to the Board, at least 15 days prior to commencement of construction at the Wapiti River, confirmation of the crossing technique to be used, a detailed construction schedule for the crossing, and any undertakings which the Company has made to DFO in respect of the crossing.

22. The Company shall submit to the Board and DFO-Habitat, prior to the commencement of construction on each spread, evidence that all required authorizations, permits, or approvals for the conduct of watercourse crossings along the subject construction spread have been obtained.

23. The Company shall submit to the Board for approval, at least 30 days prior to the conduct of pre-construction wildlife surveys:

(a) the proposed survey methodologies;

(b) for the surveys to be conducted in respect of rare and endangered species, a comprehensive list of survey locations, which also identifies the species for which each survey is being undertaken; and

(c) comments from Environment Canada regarding the survey methodologies

24. The Company shall submit to the Board for approval, at least 30 days prior to the commencement of construction activities for each spread included in the pre-construction wildlife survey:

(a) the results of the survey;

(b) any additional measures that the Company intends to use to minimize any additional effects identified as a result of the survey; and

(c) comments from Environment Canada on the results of the survey and any additional measures proposed by the Company.

25. The Company shall:

(a) conduct a pre-clearing grizzly den site survey in suitable denning habitat locations prior to clearing activities taking place in those locations;

(b) submit to the Board, at least 60 days prior to clearing in grizzly habitat areas, the methodology (including timing and locations) for the pre-clearing grizzly den site survey; and

(c) submit to the Board at least 10 days prior to clearing, the results of the pre-clearing grizzly den site survey including the results of consultations with the provincial biologist(s) and the identification of any additional mitigation measures the Company would undertake.

26. The Company shall submit to the Board, at least 30 days prior to the commencement of construction of each lateral compressor station, an ambient noise assessment for the proposed lateral compressor station site.

27. With respect to archaeological, palaeontological, and heritage resources, Alliance shall, at least 30 days prior to the commencement of construction:

(a) file with the Board confirmation that consultations with the local historical society and school board regarding the mitigation at site EfN1 10, school house memorial have been completed and provide a description of the mitigation proposed;

(b) advise the Board in writing how concerns at the following sites have been resolved:

(i) site HfRm 8 on the Highway Lateral;

(ii) sites HdRh t3, HdRh t5, HcRg t20, HcRg t21, HbRe t34, and HbRe t35 on the Aitken Creek Lateral;

(iii) sites HaRc t32, HaRc 10, HaRc t34, HaRc 11 and GIRb 2 on the Fort St. John Lateral; and

(iv) site HbRa 1 on the Boundary Lake Lateral;

(c) provide the Board with a copy of any revisions or amendments to the Historical Resource Impact Assessment/Archeological Impact Assessment ("HRIA/AIA") reports for the provinces of British Columbia, Alberta, and Saskatchewan;

(d) advise the Board in writing as to whether the HRIA/AIA reports, including any revisions or amendments thereto, and any recommendations contained therein are acceptable to the Cultural Facilities and Historical Resources Division of Alberta Community Development, the Saskatchewan Heritage Branch, and the Archaeological Branch, British Columbia Ministry of Small Business, Tourism and Culture;

(e) provide the Board with any comments received from the above-noted provincial agencies in respect of the reports, including any further mitigation; and

(f) confirm whether Alliance will comply with the mitigative measures and recommendations set out in the reports referred to in paragraph (c) and any further mitigation identified in response to paragraph (e).

28. The Company shall submit to the Board, at least 30 days prior to the commencement of construction of each compressor and meter station, a description of the measures that would be incorporated in the design to address the visual impact of the station including:

(a) the rationale for proposing those measures; and

(b) the results of consultations undertaken with respect to those measures and an indication as to whether the persons consulted are satisfied with the use of those measures.

29. Unless the Board otherwise directs, the Company shall file with the Board, at least 30 days prior to the commencement of construction:

(a) confirmation that identification of issues of concern in respect of traditional use sites has been completed with First Nations communities including, but not limited to, Doig River, Blueberry River, and Halfway River, and including:

(i) a listing of issues by First Nation;

(ii) the measures proposed to mitigate the issues identified in response to (i); and

(iii) any comments from the respective First Nations on the measures identified in response to (ii); and

(b) confirmation that the following consultations regarding traditional use sites have been completed and a description of the mitigation proposed:

(i) with the Chief and Council of the Sturgeon Lake First Nation regarding the mitigation at sites GdQn T1, Otin Meta wiwin, GdQn T3, moose lick, GcQj T1, pack trail, Sardine Lake, and Little Smoky Village;

(ii) with the Sturgeon Lake and the Kelly Lake First Nations regarding land use practices which may be affected by the construction of the pipeline; and

(iii) with the Saskatchewan Federation of First Nations in respect of monitoring burials potentially encountered during ditching operations.

30. Unless the Board otherwise directs, the Company shall submit to the Board at least 60 days prior to the commencement of construction of each construction spread (as identified in the application):

(a) an updated environmental issues list that includes the information specified by paragraph 28(1)(a) of the *Onshore Pipeline Regulations*; and

(b) for approval, an updated environmental protection plan that includes the information specified by paragraph 28(1)(b) of the *Onshore Pipeline Regulations*.

During Construction

31. Unless the Board otherwise directs, the Company shall submit construction progress reports to the Board on a monthly basis and in a form satisfactory to the Board.

32. The Company shall maintain at each construction office a copy of the applicable specifications and drawings, including the welding and nondestructive examination procedures and supporting documentation.

33. The Company shall maintain a file in each construction office containing:

(a) any information relating to applicable environmental undertakings as set out in the application or as otherwise adduced in evidence before the Board in the GH-3-97 proceeding; and

(b) copies of all applicable permits or authorizations containing environmental conditions.

34. Unless the Board otherwise directs, the Company shall:

(a) ensure that the detailed environmental inspection plan submitted to the Board for approval (pursuant to Condition 18) includes the identity, qualifications and experience of the soils specialist(s) that will be responsible for ensuring proper identification of the indicators in (i) through (vi) of paragraph (c);

(b) ensure that the soils specialist(s) identified in paragraph (a) will respond in a timely manner, to the site on any spread where wet soil indicators are likely to occur, and shall have at least equal authority to that of the construction supervisor for matters regarding the implementation of contingencies and shutdown, as well as the recommencement of construction activities following the suspension of work;

(c) implement appropriate wet soils contingency measures as described in its application or as otherwise adduced in evidence, if one of the following indicators occurs:

(i) rutting of topsoil to the extent that admixing may occur;

(ii) excessive wheelslip;

(iii) build-up of mud on tires and around cleats;

(iv) formation of extended puddles on the workspace;

(v) excessive tracking of mud along the road as vehicles leave the right-of-way; or

(vi) any other indicator that may be used to determine the potential for construction to cause an adverse effect on soils in wet condition;

(d) suspend construction in areas of native prairie if one of the above indicators occurs;

(e) suspend construction on cultivated land if one of the above indicators occurs and full-width topsoil stripping has not been undertaken; and

(f) report forthwith to the Board which wet soils contingency measures were implemented, and why they were implemented.

35. The Company shall implement a worker awareness program in regard to the potential for wildlife mortalities along roads, and its workers shall maintain reasonable reduced speeds along the right-of-way, along access roads, and, where feasible, along secondary roads. Off right-of-way traffic shall be prohibited, except for designated access routes.

36. If any previously unidentified significant habitat features, specialized habitat for wildlife with a designated status, or nesting habitat for song birds or raptors are discovered during construction, the Company shall, in consultation with the Board, Environment Canada, and other appropriate regulatory agencies, avoid, relocate, or restore these features or areas in

accordance with the procedures described in its application or as otherwise adduced in evidence before the Board in the GH-3-97 proceeding.

37. If any previously unidentified significant plant communities or plants with a designated status are discovered during construction, the Company shall, in consultation with the Board and other appropriate regulatory agencies, avoid, relocate, or restore these features or areas in accordance with the procedures described in its application or as otherwise adduced in evidence before the Board in the GH-3-97 proceeding.

38. In any fish-bearing watercourses where blasting is to be undertaken, Alliance shall conduct blasting activities in accordance with DFO's 1996 draft document entitled *Guidelines for the Use of Explosives in Canadian Fisheries Waters*.

39. For all water withdrawals from potential fish-bearing waterbodies, Alliance shall screen all water intakes in accordance with the 1995 DFO guideline entitled *Freshwater Intake End-of-Pipe Fish Screen Guideline*.

40. (a) Unless the Board otherwise directs, the Company shall submit to the Board for approval the field joining programs required by section 21 of the *Onshore Pipeline Regulations* at least 21 days prior to their being put into effect.

    (b) Notwithstanding the provisions of subsection 21(5) of the *Onshore Pipeline Regulations*, the Company shall submit to the Board for approval the field joining specifications and procedures, the procedure qualification records, and the nondestructive examination procedures for all mainline and lateral pipe having a diameter greater than or equal to 508 mm and a planned maximum operating pressure greater than or equal to 8 274 kPa.

41. Unless the Board otherwise directs, the Company shall submit to the Board for approval the pressure testing manual required by section 34 of the *Onshore Pipeline Regulations* at least 30 days prior to commencement of pressure testing.

42. Where it is necessary to exceed 10 per cent of the flow or volume of a water body when withdrawing water for hydrostatic testing purposes, the Company shall submit to the Board for approval, at least 10 days prior to commencement of water withdrawal, a hydrostatic test water withdrawal plan that, at a minimum, includes the rationale for the required exceedence, the estimated amount of the exceedence, an environmental effects assessment and mitigation plan, and results of consultation with the DFO and appropriate provincial authorities.

43. The Company shall submit to the Board for approval, and to DFO-Habitat, at least 15 days prior to completion of construction on each spread, a detailed reclamation and post-construction monitoring plan for each construction spread. This plan shall include a description of any monitoring program and special measures for post-construction control of erosion and sedimentation at watercourses, particularly those sensitive watercourses for which crossings would be constructed in winter.

Prior to the Commencement of Operation

44. Unless the Board otherwise directs, the Company shall submit to the Board for approval the emergency procedures required pursuant to sections 48 and 49 of the *Onshore Pipeline Regulations* at least 30 days prior to the commencement of operation.

45. (a) The Company shall develop, with input from regulatory agencies, including Environment Canada, and interested persons, an air quality monitoring program.

    (b) The Company shall submit to the Board a description of the air quality monitoring program referred to in paragraph (a) together with any comments received from regulatory agencies (including Environment Canada and MELP) and interested persons.

46. Unless the Board otherwise directs, the Morinville Compressor Station and the Taylor Lateral Compressor Station, in addition to the Windfall Compressor Station, shall be subject to the Company's air quality monitoring program. In the event that electric motor drivers are not used at the Bigstone Lateral Compressor Station, the Company shall, at least 15 days prior to the commencement of operation, file with the Board any comments from regulatory agencies, including Environment Canada, and interested persons regarding whether this station should be subject to the Company's air quality program including the Company's response to these comments

47. Alliance shall submit to the Board copies of the reports on the mitigation programs completed at the historical, archaeological, and palaeontological sites encountered during construction together with any comments received on these reports from the Cultural Facilities and Historical Resources Division of Alberta Community Development, the Saskatchewan Heritage Branch, and the Archaeological Branch, British Columbia Ministry of Small Business, Tourism and Culture and the respective First Nations.

Post-Construction

48. The Company shall, in accordance with the reporting schedule to be set out in its air quality monitoring program, submit to the Board the results of its emissions monitoring including a comparison to the modelled values for the stations and any comments received from Environment Canada, MELP, and interested persons regarding the results.

49. Unless the Board otherwise directs, the Company shall:

    (a) file with the Board, within 12 months after the commencement of operation of each of the mainline and lateral compressor stations, a monitoring report for each compressor station detailing the results of an appropriate noise monitoring program, including, but not limited to, the noise emission levels at the source, the fenceline, and the three closest residences, or an assessment site within or near 1.5 km from the station if no residences are within this radius, at the maximum operating level;

(b) notify the Board in writing of any noise complaint(s) received in respect of the operation of its compressor stations and apprise the Board of the results of any further noise monitoring undertaken in response and any measures that have been taken to address the complaint(s); and

(c) in the event that the noise complaint identified in response to (b) is substantiated as an increase in noise levels of 5 dBA or more, or is attributed to a specific frequency range, the Company shall undertake remedial measures within four months of receipt of the noise complaint, and in the event that implementation of the measures will take longer, or in the Company's view is not warranted, the Company shall file with the Board its justification and the results of further consultations with the affected person(s).

50. The Company shall submit to the Board, DFO-Habitat, and Environment Canada a post-construction environmental report within six months of the date that each approved facility is placed in service. The post-construction environmental report for each approved facility shall set out the environmental issues that have arisen up to the date on which the report is filed and shall:

(a) provide a description of all minor amendments to practices, procedures, and recommendations which have been implemented during the construction process;

(b) provide a summary of all instances when wet soil conditions required implementation of contingency measures or shutdown of construction, specifically identifying:

(i) the date of the decision;

(ii) the indicator(s) used for the decision and the measure/rationale applied to each indicator;

(iii) the location/geographic extent of the construction spread affected, and soil type;

(iv) the nature of work being affected by the decision;

(v) the specific contingency measures that were implemented;

(vi) the date contingency measures were no longer required or construction recommenced and the rationale for the decision; and

(vii) any specific follow-up, reclamation, or monitoring recommended;

(c) indicate those issues which have been resolved and those unresolved;

(d) describe the measures which the Company proposes to take in respect of unresolved issues;

(e) include copies of any as-built reports that are prepared in accordance with undertakings made to DFO, and any comments from DFO in respect of those reports; and

(f) provide a list and suitable map indicating all designated access routes and the location and type of all temporary facilities.

51. The Company shall submit to the Board, on or before December 31st following each of the first two complete growing seasons which occur after the filing of the post-construction environmental report referred to in Condition 50:

(a) a list of the environmental issues indicated as unresolved in the report and any that have arisen since the report was filed; and

(b) a description of the measures which the Company proposes to take in respect of any unresolved environmental issues.

52. Unless the Board otherwise directs, the Company shall submit to the Board, in conjunction with the final report filed pursuant to Condition 51, a videotape or remote sensing imagery of the entire pipeline right-of-way, in a form that is satisfactory to the Board.

53. Unless the Board otherwise directs, the Company shall submit to the Board:

(a) within six months after the commencement of operation of the pipeline, a description of its heat effects monitoring program for vegetation located along the right-of-way downstream of the mainline compressor stations, including the parameters to be monitored, the frequency of monitoring, and the benchmarks to be used for comparison in addition to any comments from landowners and interested persons on the program; and

(b) in accordance with the reporting schedule to be set out in its heat effects monitoring program, the results of the Company's monitoring program including any comments on the results from landowners and other interested persons.

Expiration of Certificate

54. Unless the Board otherwise directs, this certificate shall expire in its entirety on 31 December 2000 unless the construction of the Alliance Pipeline Project has commenced by that date, and shall expire five years from the date of this certificate in respect only of any facilities authorized by this certificate which have not been constructed by that time.

Table V-1
Concordance Between CSR Recommendations and Certificate Conditions

CSR Recommendation	Certificate Condition		CSR Recommendation	Certificate Condition
1	8		22	16
2	9		23	45
3	34		24	46
4	19		25	48
5	37		26	10
6	11		27	26
7	20		28	49
8	21		29	27
9	22		30	47
10	42		31	28
11	38		32	29
12	39		33	44
13	6		34	33
14	5		35	18
15	7		36	43
16	23		37	50
17	24		38	51
18	25		39	52
19	36		40	53
20	35		41	2
21	17			

Appendix VI

Excerpts from Shipper Agreements re NGLs

The following are excerpts from the pro forma Precedent and Transportation Service Agreements for the firm transporation of natural gas on the Canadian portion of the Alliance Pipeline (both of which were filed in conjunction with Alliance's application to the Board) relating to natural gas liquids and liquefiable hydrocarbons:

Precedent Agreement

Article 5.5 - Relinquishment of Rights to Liquids

The Transportation Service Agreement will provide for the full relinquishment by the Shipper of any rights to deliveries of a specific portion of the common stream of Natural Gas transported by the Transporter and the U.S. Transporter, and to rights of natural gas liquids or liquefiable hydrocarbons that may be removed or processed from such common streams and all proceeds, profits and losses derived from or allocable to the removal, processing or sale of such liquids or liquefiable hydrocarbons (collectively, "the relinquishment rights"). The Shipper will, at the time of execution and delivery of the Transportation Service Agreement, or at any time thereafter as required by the Transporter, execute and, if required by the Transporter, cause the execution of by any of its Affiliates or any other Person who has been allocated transportation service on the U.S. Pipeline for volumes of Natural Gas corresponding to the Contracted Capacity any agreements or instruments specifically providing for such relinquishment of rights, in the form required by the Transporter; provided that such agreement or instrument will:

(a) not affect, vary or alter the tolls payable for transportation service under the Transportation Service Agreement;

(b) not affect, vary or alter the entitlement of the Shipper to have deliveries made to it by the U.S. Transporter balanced with its deliveries to the Transporter on a heating value basis, after allowance for line losses and Fuel, at U.S. delivery points.

Transportation Service Agreement

Article 5 - Option to Extract and Purchase Liquids

5.1 Shipper's receipts and deliveries, less Fuel, will be balanced on volume and heating value bases at the Delivery Point in accordance with the Tariff.

5.2 Shipper hereby grants to the Transporter acting solely in its capacity as agent for the parties identified in Schedule B (the "Optionees"), the option, exercisable at any time or times, and for any periods during the term of this Transportation Service Agreement, to extract from the commingled Natural Gas transported by the Transporter and purchase all Natural Gas liquids or liquefiable hydrocarbons received by the Transporter from the Shipper that Optionees elect to remove or process and herby relinquishes to the Transporter, acting solely in its capacity as agent for the Optionees, all proceeds, profits and losses derived from or allocable to the removal, processing or sale of such Natural Gas liquids or liquefiable hydrocarbons.

5.3 At any time that the Optionees exercise their option, then in consideration for the sale by the Shipper of the extracted Natural Gas liquids or liquefiable hydrocarbons, the Transporter solely in its capacity as agent for the Optionees, shall arrange for the delivery to the Shipper by the U.S. Transporter at delivery points on the U.S. Pipeline of quantities of Natural Gas that have a heating value equal to the heating value of the quantities of such extracted Natural Gas liquids or liquefiable hydrocarbons acquired by the Optionees.

5.4 The Shipper will, at the time of execution and delivery of this Transportation Service Agreement, or at any time thereafter as required by the Transporter, execute, and, if required by the Transporter, cause the execution of by any of its Affiliates or any other person who has been allocated transportation service on the U.S. Pipeline for volumes of Natural Gas corresponding to the Contracted Capacity, agreements or instruments specifically providing for the option created in Section 5.2 or the acknowledgement of such option in the forms required by the Transporter, provided that such agreements or instruments will not:

(a) affect, vary or alter the amounts payable by Shipper for transportation service under this Transportation Service Agreement; or

(b) affect, vary or alter the entitlement of the Shipper to have deliveries made to it by the Transporter at the Delivery Point balanced with its deliveries to the Transporter on a heating value basis, after allowance for Fuel; or

(c) affect, vary or alter the entitlement of the Shipper or its Affiliates or any other Person who has been allocated transportation service on the U.S. Pipeline to have deliveries made to it by the U.S. Transporter at delivery points on the U.S. Pipeline balanced with its deliveries to the U.S. Transporter on a heating value basis, after allowance for fuel.

Appendix VII

Order TG-7-98

IN THE MATTER OF the *National Energy Board Act* ("*NEB Act*") and the Regulations made thereunder; and

IN THE MATTER OF an application dated 3 July 1997 by Alliance Pipeline Ltd. ("Alliance") on behalf of the Alliance Pipeline Limited Partnership for an order pursuant to Part IV of the *NEB Act*, filed with the National Energy Board ("Board") under File 3200-A159-1.

BEFORE the Board on 23 November 1998;

WHEREAS Alliance filed an application dated 3 July 1997 for an order approving the toll methodology and the tariff that is to apply in respect of service provided by Alliance;

AND WHEREAS a public hearing was held pursuant to Hearing Order GH-3-97 during which time the Board heard evidence and argument presented by Alliance and interested persons;

AND WHEREAS the Board's decisions on the application are set out in the GH-3-97 Reasons for Decision dated November 1998 and in this Order;

IT IS ORDERED THAT:

1. Alliance shall, for accounting, toll-making, and tariff purposes, implement the decisions outlined in the GH-3-97 Reasons for Decision and in this Order; and

2. At least sixty days prior to the commencement of operation of the pipeline, Alliance shall file with the Board, and serve on all GH-3-97 full participation intervenors, tariffs (including general terms and conditions) and tolls conforming to the decisions outlined in the GH-3-97 Reasons for Decision and in this Order.

NATIONAL ENERGY BOARD

Michel L. Mantha
Secretary

National Energy Board
Office national de l'énergie

Reasons for Decision

Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP and Enbridge Pipelines Inc.

OH-3-2007

February 2008

Facilities

Canada

National Energy Board

Reasons for Decision

In the Matter of

Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP and Enbridge Pipelines Inc.

Application dated 9 March 2007 for the Southern Lights Project consisting of the:
1. Diluent Pipeline Project; and
2. Capacity Replacement Project.

OH-3-2007

February 2008

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Glossary of Terms, Acronyms and Abbreviations

Southern Lights Project	Two projects, more properly described as: 1. Diluent Pipeline Project consisting of the: a) Transfer of Line 13; b) Line 13 Reversal; and 2. Capacity Replacement Project consisting of the: a) Line 2 Modifications b) Light Sour Pipeline
Alberta Clipper Project	Alberta Clipper Expansion Project
Annual capacity	The average daily rate that the pipeline system is able to generate on an annual basis.
API	American Petroleum Institute
Applicants	Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP and Enbridge Pipelines Inc.
Apportionment	The method of allocating the difference between the total shipper nominated volume on Enbridge Pipelines Inc.'s mainline and the available pipeline operating capacity, where the latter is smaller.
bbl/d	barrel(s) per day
Board or NEB	National Energy Board
CAPP	Canadian Association of Petroleum Producers
CE	carbon equivalent
CEA Act	*Canadian Environmental Assessment Act*
CEA Agency	Canadian Environmental Assessment Agency
CEP	Communication Energy and Paperworkers Union of Canada
Certificate	Certificate of Public Convenience and Necessity
Committed shippers	Shippers that have executed a Transportation Service Agreement that provides for the transportation of a stated daily volume for an initial term of 180 calendar months on the reversed Line 13.
CSA	Canadian Standards Association

CSA Z662	Latest applicable version of the CSA standard Z662, Oil and Gas Pipeline Systems, as amended from time to time
CSA Z662-03	CSA standard Z662, Oil and Gas Pipeline Systems, 2003
CSA Z662-07	CSA standard Z662, Oil and Gas Pipeline Systems, 2007
Dakota Nations of Manitoba	Dakota Nations of Manitoba (On behalf of Birdtail Sioux First Nation, Canupawakpa Dakota Nation, Dakota Plains First Nation, Dakota Tipi First Nation and Sioux Valley Dakota Nation)
dilbit	A blend of condensate and *in situ* bitumen primarily used in heavy crude refineries.
DRA	drag reducing agent
EA	engineering assessment
EPI	Enbridge Pipelines Inc.
EPP	Environmental Protection Plan
ERP	Emergency Response Plan
ERW	electrical resistance weld
ESL	Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP
ESR	Environmental Screening Report
FA(s)	Federal Authority as defined in subsection 2(1) of the *Canadian Environmental Assessment Act*
ha	hectare(s)
ILI	in-line inspection
IMP	Integrity Management Program
INAC	Indian and Northern Affairs Canada
Interim Period	the period between the in-service date for the Capacity Replacement Project and the closing date for the Line 13 transfer
Keystone	TransCanada Keystone Pipeline GP Ltd.
km	kilometre(s)
KP	kilometre post
kPa	kilopascal(s)

Line 2 Modifications	Proposed modifications to Line 2 outlined in section 5.1.1 of the Reasons.
Line 13	Line 13 pipeline and related facilities
Line 13 Transfer	Transfer of the Canadian portion of Line 13 from EPI to Enbridge Southern Lights LP in accordance with an agreement between EPI and Enbridge Southern Lights LP dated 9 March 2007.
Line 13 Reversal	Removal of Line 13 from southbound crude oil service and reversal of Line 13 to transport diluent from the Canada/US border near Gretna, Manitoba to Edmonton, Alberta
LSr Pipeline	Light Sour [crude oil] Pipeline and related facilities
LSr Station Facilities	LSr Pipeline pumping and related facilities and pump station piping at three existing EPI pump station sites
LVP	low vapour pressure
m	metre(s)
mm	millimetre(s)
MBS	material balance system
m^3/d	cubic metre(s) per day
MOP	maximum operating pressure(s)
MPLA	Manitoba Pipeline Landowners Association
NEB	National Energy Board
NEB Act	*National Energy Board Act*
NDE	non-destructive examination
NGL	Natural Gas Liquids
NPS	nominal pipe size (in inches)
OD	outside diameter
OPR-99	*Onshore Pipeline Regulations, 1999*
OPUAR	*Oil Pipeline Uniform Accounting Regulations*
Peepeekisis	Peepeekisis First Nation
PIP	Preliminary Information Package
PPBoR	plan, profile and book of reference

Project	Southern Lights Project
RA(s)	Responsible Authority as defined in subsection 2(1) of the *Canadian Environmental Assessment Act*
RoW	right-of-way
Roseau River	Roseau River Anishinabe First Nation
RTTM	real-time transient model
SAPL	Saskatchewan Association of Pipeline Landowners
SCADA	supervisory control and data acquisition
SCC	stress corrosion cracking
Shipper	The party that contracts or nominates with a pipeline for transportation service.
SMAW	shielded metal arc welding
Standing Buffalo	Standing Buffalo Dakota First Nation
synbit	synthetic bitumen
Transfer Agreement	Agreement between EPI and Enbridge Southern Lights LP dated 9 March 2007 for the transfer of Line 13.
TSA	Transportation Service Agreement
US	United States of America
USCD	ultrasonic crack detection
WCSB	Western Canadian Sedimentary Basin

Recital and Appearances

IN THE MATTER OF the *National Energy Board Act* and the Regulations made thereunder; and

IN THE MATTER OF an application under file number OF-Fac-Oil-E242-2007-01 01 by Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP (ESL), and Enbridge Pipelines Inc. (EPI), collectively the Applicants, dated 9 March 2007 for:

a) Diluent Pipeline Project

1. Leave to be granted to EPI pursuant to subsection 74(1)(a) of the *National Energy Board Act* (NEB Act), to sell Line 13 and such other orders, pursuant to Part IV and section 20 and subsection 129(1.1) of the NEB Act, which are necessary to effect the transfer of Line 13 in accordance with the terms and conditions set out in the Transfer Agreement.

2. Leave to be granted to ESL pursuant to subsection 74(1)(b) of the NEB Act, to purchase Line 13 and such other orders pursuant to Part IV and section 20 and subsection 129(1.1) of the NEB Act, which are necessary to effect the transfer of Line 13 in accordance with the terms and conditions set out in the Transfer Agreement.

3. An order to be granted to EPI pursuant to section 58 of the NEB Act, authorizing the construction and operation of the Line 13 Reversal facilities and exempting these facilities from the provisions of sections 30, 31 and 47 of the NEB Act.

4. Approval to be granted to EPI under Part IV of the NEB Act, for the toll principles and the tariff that will apply to the transportation of diluent on the Line 13 Reversal.

b) Capacity Replacement Project

1. A Certificate of Public Convenience and Necessity to be issued to EPI pursuant to section 52 of the NEB Act, authorizing the construction and operation of the LSr Pipeline.

2. An order to be granted to EPI pursuant to section 58 of the NEB Act exempting the pumping facilities, related facilities and pump station piping associated with the LSr Pipeline from the provisions of subsections 30(1)(b), 31(c), 31(d) and section 47 of the NEB Act, upon the issuance of a Certificate for the LSr Pipeline.

3. An order to be granted to EPI pursuant to section 58 of the NEB Act authorizing EPI to construct and operate the Line 2 Modification facilities and exempt these facilities from the provisions of sections 30, 31 and 47 of the NEB Act.

4. Approval to be granted to EPI under Part IV of the NEB Act for the tolling methodology to apply to the Line 2 Modifications and the LSr Pipeline prior to the transfer of Line 13 from EPI to ESL.

AND IN THE MATTER OF National Energy Board Hearing Order OH-3-2007 dated 17 April 2007;

HEARD in Calgary, Alberta on 13 and 14 August 2007, 29 and 31 October 2007 and in Regina, Saskatchewan on 20 and 21 August 2007;

BEFORE:

S. Crowfoot	Presiding Member
K. Batemen	Member
S. Leggett	Member

Appearances	**Company**	**Witnesses**
Mr. D.G. Davies Mr. T. Hughes Ms. H. Long Mr. E. Dixon	Applicants	Ms. K. McShane Mr. J. Glanzer Mr. M. Thompson Mr. R. Fisher Mr. N. Earnest Mr. M. Sitek Ms. J. Whitney Mr. L. Neis Mr. L. Zupan Ms. G. Feltham Mr. K. Gilmore Mr. G. Herchak Mr. J. Gerez Mr. W. Forbes Mr. R. Wight Mr. J. Paetz Ms. T. Petter
Mr. N. J. Schultz Mr. L. Manning	Canadian Association of Petroleum Producers	
Ms. C. G. Worthy	BP Canada Energy Company	
Ms. C. Fredericks	ConocoPhillips Canada Limited	
Mr. D.A. Holgate	Statoil North America, Inc.	
Mr. J. Van Heyst	Suncor Energy Marketing Inc.	

Appearances	Company	Witnesses
Ms. J. Scott	TransCanada Keystone Pipeline GP Ltd	
Mr. S. Shrybman	Communications, Energy and Paperworkers Union of Canada	Mr. J.E. Wilson
Mr. M. Phillips	Standing Buffalo Dakota	Chief Roger Redman
Ms. M. Rasmussen, Q.C.	First Nation	Elder Dennis Thorne Elder Cliff Tawiyala Elder Wayne Goodman
Ms. K. Lozynsky Mr. P. Enderwick	National Energy Board	

Chapter 1

Introduction

1.1 Background

On 9 March 2007, Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP (ESL) and Enbridge Pipelines Inc. (EPI), collectively the Applicants, applied to the National Energy Board (NEB or the Board) for approvals related to the Southern Lights Project (Project).

This Project consists of two components:

1) a Diluent Pipeline Project; and

2) a Capacity Replacement Project.

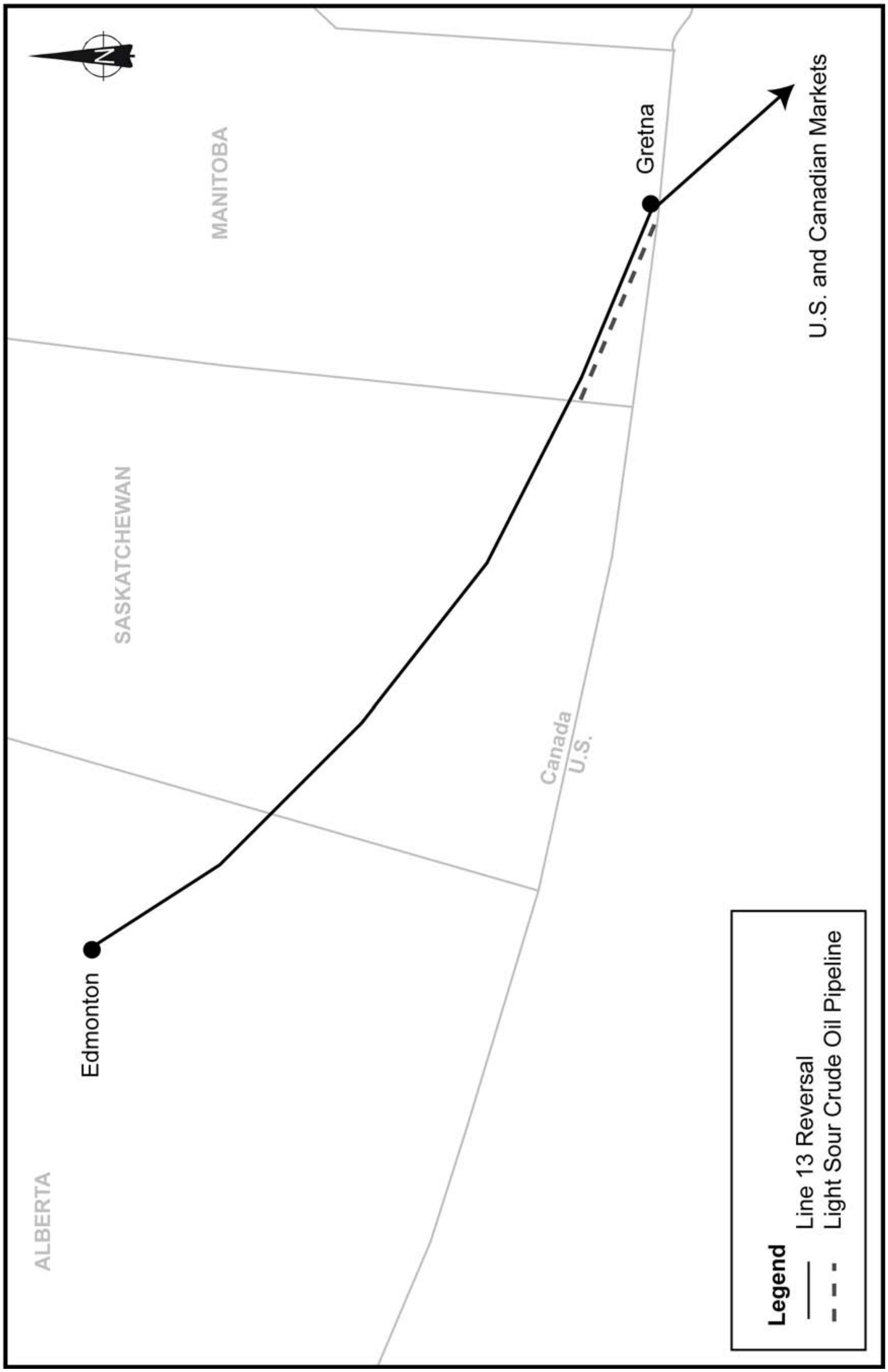
1.2 Diluent Pipeline Project

The Diluent Pipeline Project involves the transfer of the Canadian portion of Line 13 from EPI to ESL (Line 13 Transfer) in accordance with a Transfer Agreement dated 9 March 2007 (Transfer Agreement) and therefore requires leave pursuant to section 74 of the *National Energy Board Act* (NEB Act) as well as an order pursuant to subsection 129(1.1). EPI's Line 13 would be removed from southbound crude oil service and reversed to transport diluent from the Canada/US border near Gretna, Manitoba to Edmonton, Alberta (Line 13 Reversal) (see Figure 1-1). No new pipeline or pumps would be required in Canada as part of the Line 13 Reversal and all work would occur within existing Line 13 pump station and valve sites. ESL has applied for a section 58 order and approval under Part IV of the NEB Act in relation to the Line 13 Reversal.

1.3 Capacity Replacement Project

The proposed Capacity Replacement Project would offset the reduction of southbound crude oil capacity on the EPI Mainline system resulting from the Line 13 Reversal and would consist of the construction of a 288 km, 508 mm OD (NPS 20) light sour pipeline (LSr Pipeline) from Cromer, Manitoba to the Canada/US border near Gretna, Manitoba, including the addition of pumping and related facilities and pump station piping at three existing EPI pump station sites (LSr Station Facilities) and modifications to Line 2 (Line 2 Modifications). EPI has applied under the NEB Act, pursuant to section 52 for a Certificate to construct and operate the LSR Pipeline and for two section 58 orders related to the LSr Station Facilities and Line 2 Modifications. EPI has also asked for approval under Part IV of the NEB Act for the tolling methodology to apply to the Line 2 Modifications and the LSr Pipeline prior to the transfer of Line 13 from EPI to ESL and the Line 2 Modifications.

Figure 1-1
Southern Lights Project



1.4 Regulatory Context

On 14 November 2006, the Applicants filed a Preliminary Information Package (PIP) respecting the Project. The purpose of the PIP was to initiate and facilitate an efficient regulatory review of the Project and enable the Board and other federal departments to determine their respective environmental assessment responsibilities and the scope of the assessment under the Canadian Environmental Assessment Act (CEA Act).

The applications were filed 9 March 2007. By letter of 18 April 2007, the Board announced that it would convene an oral public hearing beginning 13 August 2007. Hearing Order OH-3-2007 set out the procedures to be followed in the hearing. Parties wanting to intervene in the proceeding were given until 14 May 2007 to apply. The Board received 17 applications for intervenor status.

In its 18 April 2007 letter, the Board invited parties to suggest any amendments or additions to the List of Issues by 14 May 2007. The Board received comments from the Communications, Energy and Paperworkers Union of Canada (CEP) and the Dakota Nations of Manitoba on behalf of the Birdtail Sioux First Nation, Canupawakpa Dakota First Nation, Dakota Plains First Nation, Dakota Tipi First Nation and Sioux Valley Dakota Nation (Dakota Nations of Manitoba). The concerns raised by these parties related to value-added processing and the Dakota traditional territory, respectively.

By letter dated 23 May 2007, the Board advised that it would revise the List of Issues (found in Appendix I) to include the following: Impacts of the Project on Aboriginal People.

On 27 April 2007, the Board requested comments from the public on the draft scope of the environmental assessment of the Project. After considering the comments received from the Meewasin Valley Authority and Roseau River Anishinabe First Nation (Roseau River), the Board and the other Responsible Authorities (RAs) for the Project, Transport Canada and Indian and Northern Affairs Canada (INAC), determined the scope of the environmental assessment.

On 6 July 2007, the Manitoba Pipeline Landowners Association and Saskatchewan Association of Pipeline Landowners (MPLA/SAPL) filed a motion for orders to adjourn the Southern Lights hearing and consolidate the hearing with that of the Alberta Clipper Expansion Project (Alberta Clipper Project). As alternatives to consolidation, the MPLA/SAPL asked the Board to either reschedule the hearing at the same time in the same locations as the Alberta Clipper Project hearing, or, in order to enable interested landowners to attend the hearing, commence the hearing no earlier than 29 October 2007 to avoid harvest.

After considering the submissions of parties, the Board denied the request for adjournment and consolidation with the Alberta Clipper Project application. However, the Board scheduled hearings in Regina to accommodate the participation of Standing Buffalo Dakota First Nation (Standing Buffalo) and in Brandon to accommodate the participation of the MPLA/SAPL. Further information on this motion and others can be found in Appendix II.

By letter dated 19 October 2007, the MPLA/SAPL withdrew from the proceeding resulting in the cancellation of the Brandon hearing. The Board held the last phase of the hearing in Calgary commencing on 29 October 2007.

The public hearing was held on:

- 13, 14 August 2007 in Calgary, Alberta;
- 20, 21 August 2007 in Regina Saskatchewan; and
- 29, 31 October 2007 in Calgary, Alberta.

The Board used a life cycle approach in considering the Project. This means that all issues and concerns before the Board were considered in the context of the entire Project life cycle (i.e., design, planning, construction, operation, decommissioning and abandonment).

As an RA under the CEA Act, the Board completed an Environmental Screening Report pursuant to the CEA Act. The Report is provided as Appendix V to these Reasons. Further discussion of environmental matters can be found in Chapter 3 of these Reasons.

1.5 The Board’s Public Interest Determination

Mandate of the Board

The NEB is an independent federal agency that regulates several aspects of Canada's energy industry. It was established in 1959 by Parliament by virtue of the proclamation of the NEB Act which transferred to the Board the responsibility for pipelines and certain matters related to oil, gas and electricity.[1] In addition, it granted the Board responsibility for regulating tolls and tariffs, and defined its jurisdiction and status as an independent court of record.

The NEB’s purpose is to promote safety, environmental protection and economic efficiency in the Canadian public interest in its regulation of pipelines, international power lines and energy development, within the mandate set by Parliament. As part of its mandate, the Board, as a quasi-judicial tribunal, may hold public hearings in order to hear all sides and points of view prior to making decisions on applications for new facilities that fall within its jurisdiction. In carrying out its quasi-judicial duties, the Board is bound by its mandate under the NEB Act. In certain instances, such as this one, the Board also has responsibilities under the CEA Act.

With respect to the Southern Lights Project, part of the applicable legal framework is found in Parts III and IV of the NEB Act. Part III of the NEB Act requires the Board to make a determination with respect to the present and future public convenience and necessity in the Canadian public interest. Part IV of the NEB Act requires that the Board make certain determinations with respect to tolls and tariffs. In making its determinations, the Board must rely only on the facts that are established through the hearing process and must proceed in compliance with the principles of natural justice.

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1 As defined in the division of powers between the provinces and the Federal government under sections 91 and 92 of the *Constitution Act, 1867*.

The Public Interest

The Board has described the public interest as:[2]

> The public interest is inclusive of all Canadians and refers to a balance of economic, environmental, and social interests that change as society's values and preferences evolve over time. As a regulator, the Board must estimate the overall public good a project may create and its potential negative aspects, weigh its various impacts, and make a decision.

Under the NEB Act, the factors to be considered and the criteria to be applied in coming to a decision on public interest or the present and future public convenience and necessity may vary with the circumstances, including the application, the location, the commodity involved, the various segments of the public affected by the decision, societal values at the time, and the purpose of the applicable section of the NEB Act.

In this proceeding, the Board heard evidence on engineering design and safety issues; economic considerations, such as supply and markets; public engagement and consultation; impacts on Aboriginal people; socio-economic and environmental effects of the Project; and land and routing matters.

The Board has determined that all of these factors are relevant in deciding whether the Southern Lights Project is in the public interest.

These Reasons also address issues arising from the applications pursuant to Part IV with respect to the tolls and tariff on the Line 13 Reversal, LSr Pipeline and Line 2. The Board's determination on whether the proposed tolling principles and tolling methodologies are just and reasonable is contained in sections 4.2.4 (along with the Board's decision on the requested method of regulation for the Line 13 Reversal) and 5.5.

2 See the Board's Internet site at http://www.neb-one.gc.ca/PublicInterestFootnote_e.htm

Chapter 2

Standing Buffalo Dakota First Nation Motion

On 3 May 2007, Standing Buffalo filed an application for intervenor status in the Enbridge Southern Lights OH-3-2007 Hearing, in which it cited unextinguished Aboriginal title, self-governance rights and historic allyship status as the basis for its participation in the process.

As a preliminary matter at the oral hearing, counsel for Standing Buffalo raised two issues before the Board. The Board subsequently requested that these preliminary matters be filed by way of a Notice of Motion pursuant to section 35 of the *National Energy Board Rules of Practice and Procedure*, *1995.*

The Notice of Motion was subsequently filed and requested the following decisions of the Board:

(a) a decision that the Board has no jurisdiction to consider the Southern Lights Application on its merits without first determining whether Standing Buffalo has a credible claim within the meaning of the Supreme Court's decision in *Haida Nation v. British Columbia (Minister of Forests),* [2004] 3 S.C.R.511, S.C.J. No. 70 ('*Haida*'); and

(b) a decision that the duty of fairness requires that the Crown be required to attend and respond to Standing Buffalo's claim, and that, in the absence of any such response from the Crown, Standing Buffalo's claim should be accepted as uncontradicted and the Board should then determine that it is without jurisdiction to determine the substantive merits of the Southern Lights applications.

In support of the motion, Standing Buffalo provided evidence by way of affidavit and witness testimony during the Southern Lights hearing.

Upon receipt of the Notice of Motion, the Board established a process to allow other parties an opportunity to answer the motion and to allow for a reply from Standing Buffalo. This process was subsequently amended to allow for further reply following the argument portion of the hearing. The Board reserved its decision on the motion.

2.1 Submissions on the Motion

Standing Buffalo

Standing Buffalo asserts a claim of Aboriginal title over land where the Project is proposed to be located. Standing Buffalo submitted that it has a credible potential claim and thus the test set out in *Haida* is engaged. Standing Buffalo submitted that the NEB can only consider the substance of the Southern Lights applications once it has: (1) established that Standing Buffalo has made a credible potential claim to the land subject to the Project; (2) determined the scope of the Crown's duty to consult; and (3) satisfied itself that the Crown's duty to consult has been fulfilled.

Standing Buffalo asserted that its Aboriginal right to the land has existed since time immemorial and noted that Standing Buffalo has not entered into a treaty. According to Standing Buffalo, this combined with the relationship with the Crown premised on allyship, gives rise to a credible claim to governance rights.

Standing Buffalo argued that the fact that the Crown engaged in negotiations over the course of many years suggests that the Crown believes the claim is in fact credible. Standing Buffalo further submitted that, even though the Crown's response to it may have been negative, because the Crown has not appeared to contradict Standing Buffalo's position in this proceeding, one may conclude that the Crown does not take issue with the "existence" of Standing Buffalo's credible potential claim. Standing Buffalo took the position that the duty of fairness requires the Crown to respond to its claim and, if that does not occur, the NEB ought to find that it does not have jurisdiction to consider Southern Lights applications.

In the view of Standing Buffalo, the fact that the Project is proposed to be built on Dakota lands is a potential adverse effect as contemplated in *Haida* because it interferes with constitutionally protected governance rights. According to Standing Buffalo, the proposed pipeline would directly affect its right to control its traditional territory as a result of its assertion of Aboriginal title.

Standing Buffalo submits that the Board must first conclude that the Crown owes a duty to consult before assessing the adequacy of consultation. The strength of the claim and significance of the adverse effect should only be considered at the next step, determining the scope of the duty to consult and whether the Crown's consultation has met that standard. Standing Buffalo maintained that the Crown did not inform Standing Buffalo of the Project.

Standing Buffalo also argued that the public hearing process cannot satisfy the Crown's duty to consult because the NEB is not an agent of the Crown and that, unlike the Crown, the NEB does not owe a fiduciary duty to Standing Buffalo. It further argued that the Applicants' consultation cannot satisfy the Crown's duty because, although its consultation may satisfy the Crown's duty under certain circumstances, the Applicants are not capable of conducting meaningful consultation in relation to governance. Standing Buffalo claimed that the Applicants' consultation was perfunctory and not sufficient in the non-treaty context.

In summary, Standing Buffalo submitted that the Board must either order Canada to be present so that all parties may address the issue of jurisdiction with Canada present, or it must determine it has no jurisdiction to consider the merits of the substantive application before it.

Enbridge Southern Lights LP and Enbridge Pipelines Inc.

ESL and EPI submitted that the motion should be dismissed as there is no basis for the Board to decide as requested by Standing Buffalo. They submitted that, while the Board may issue a subpoena, a subpoena cannot simply be directed to the Crown. Further, ESL and EPI argued that no useful purpose would be served by doing so as it was already clear from the evidence that the Government of Canada does not accept the claims of Standing Buffalo. According to ESL and EPI, additional evidence of such claims would have limited probative value as it is not within the mandate of the Board to adjudicate on such matters.

EPI and ESL argued that the duty of Crown consultation does not arise just from the demonstration of a credible claim. There must also be a demonstration that the activity being proposed might adversely affect the claimed aboriginal rights.

ESL and EPI submitted that there is no reason or justification for the Board to either order the Crown to be present at the hearing or to make a preliminary determination about its jurisdiction to consider the merits of the Southern Lights applications.

Canadian Association of Petroleum Producers (CAPP)

CAPP opposed the motion and argued that the consequence of Standing Buffalo’s position is unreasonable and that it is not supported by law. Further, CAPP submitted that the fundamental issue of concern to Standing Buffalo is beyond the jurisdiction of the NEB.

CAPP further argued that regulatory consideration of a development proposal does not require, as a precondition to the exercise of jurisdiction, the settlement of any claim. CAPP claimed that the fundamental issue for Standing Buffalo is to have the Crown respond favourably to its asserted rights and that its intervention in the NEB process is collateral to this fundamental issue. CAPP submitted that the Board cannot resolve that fundamental issue. Moreover, CAPP argued that the NEB does not have jurisdiction to refuse to process applications that meet regulatory requirements because of unresolved claims against the Crown and; furthermore, the case law does not require the Board to halt its process.

In response to Standing Buffalo’s assertion that the NEB must accept Standing Buffalo evidence if it is uncontradicted, CAPP argued that there is no such rule of law applicable to NEB proceedings. Further, CAPP submitted that despite Standing Buffalo’s assertion that the Crown has been silent, the evidence of Standing Buffalo shows that that has not been the case. In support, CAPP pointed to the evidence that Standing Buffalo had received a letter from the Government that was not favourable to the Standing Buffalo position, that it had met with the Honourable Bill McKnight and that the Canadian Environmental Assessment Agency (CEA Agency) had been in communication with Standing Buffalo.

CAPP submitted that unresolved claims do not present an absolute bar to ongoing activities or further development. According to CAPP, consultation is a process that leads to a balancing of interests and decisions can be made though there may be disagreement about the adequacy of the Crown’s response. Finally, CAPP argued that unreasonable attempts to thwart decision-making are not permissible.

Reply Submissions of Standing Buffalo

In reply, Standing Buffalo clarified that it is not its position that any credible potential claim will automatically halt any development whatsoever. Standing Buffalo stated that a credible potential claim must be analyzed in accordance with the test in *Haida* based on a preliminary assessment of the strength of the credible potential claim and of the negative effect on the credible potential claim of the development being promoted. Standing Buffalo argued that the Board must conduct this analysis first in order to determine whether or not it has jurisdiction to proceed with the substantive merits of the application because, in some cases, the Crown’s duty to consult and accommodate extends to the point of requiring the consent of the Aboriginal peoples affected.

According to Standing Buffalo, a review of the claim is required in order to determine if it is a credible potential claim and then it can be decided if consent is required.

In response to CAPP's argument that Standing Buffalo's claim should be rejected on the basis that, to accept it, would halt development, Standing Buffalo submitted that this is not the correct test to be applied.

It was also Standing Buffalo's position that the Board cannot properly assess either the strength of the claim or the negative effects of the Project on the claim without Canada being present to respond to the claim. Therefore, Standing Buffalo maintained that the Board should invite Canada to attend and respond to Standing Buffalo so that the Board would be in a position to conduct a preliminary assessment and to determine whether or not consent is required.

In response to the suggestion of EPI and ESL that the Board has no jurisdiction to join the Crown in these proceedings, Standing Buffalo argued that this ignores the fact that the honour of the Crown is engaged and that it is therefore not necessary for the Board to subpoena the appropriate representatives of the Crown to respond to Standing Buffalo's claim.

Standing Buffalo reiterated its objection to CAPP's reference to without prejudice communications that suggest that the Crown has rejected Standing Buffalo's claim.

According to Standing Buffalo, the content of these communications is not in evidence before the Board and so any conclusions that the respondents may have drawn about the content is speculative at best. Standing Buffalo argued that whether or not the Crown accepts or rejects a claim made by Aboriginal peoples does not determine that the claim is or is not credible. That assessment must be made objectively, in this case initially by the Board subject to review by the courts. Further, Standing Buffalo submits that preliminary assessment of their claim cannot be made without the Crown's response to it because although the Crown's opinion is not determinative, it will assist the Board by providing a complete picture of the circumstances of Standing Buffalo's claim.

2.2 The Board's Ruling on the Motion

The foundation for Standing Buffalo's motion is that the Project falls within the territory over which it asserts Aboriginal rights and title. Standing Buffalo claims Aboriginal rights and title over a vast territory that spans three Prairie provinces and a substantial portion of the northern United States. Though there have been negotiations between Standing Buffalo and the Government of Canada for several years, according to Standing Buffalo, its issues have not been resolved.

The Board's understanding of Standing Buffalo's position is that, since it has a credible potential claim, prior to considering the substantive merits of the Application, the Board must address the jurisdictional question of whether the Crown's duty to consult with Standing Buffalo has been fulfilled in accordance with the test in *Haida.* Standing Buffalo maintained that this analysis requires a determination of the scope of the duty to consult, which involves an evaluation of the strength of the Standing Buffalo claim and the adverse impacts or effects on that claim. Standing

Buffalo further maintained that, for the Board to fully consider and answer the questions raised by Standing Buffalo, the Crown must be present to respond.

The Board does not agree with Standing Buffalo's position that, before it considers the substantive merits of the Certificate application, it must determine the strength of Standing Buffalo's claim and assess the adequacy of Crown consultation. The Board's process is designed to ensure that it has a full understanding of the concerns that Aboriginal people have in relation to a project before it renders its decision. Aboriginal people who have an interest in a project are able to participate in the regulatory process on several levels. The Board weighs and analyzes the nature of the Aboriginal concerns and the impacts a proposed project might have on those interests as part of its overall assessment of whether or not the project is in the public interest. The Board notes that most projects, including the Southern Lights Project, require various permits and authorizations from other federal or provincial government departments. For the reasons discussed below, the Board is not in a position to assess whether the legal obligations of those departments and agencies, including the adequacy of their consultations, have been fulfilled in relation to those permits and authorizations. The Board is of the view that the process it followed in the evaluation of the Southern Lights Project ensures that the decisions of the Board in respect of the Project will be made in accordance with all legal imperatives.

To understand why the Board has adopted these views, it is relevant to examine the Board's jurisdiction and process in some detail.

2.2.1 Board Jurisdiction and Process

The NEB was established by Parliament through the NEB Act to carry out a number of functions pertaining to energy and energy infrastructure in Canada. Among those functions is the assessment of applications for the construction and operation of pipelines and related facilities for the purpose of granting or denying orders, or issuing certificates subject to Governor in Council approval. The Board does not have the jurisdiction to settle Aboriginal land claims.

The Board weighs the overall public good a project may create against its potential negative aspects, including any negative impacts on Aboriginal interests, and makes its decisions in accordance with the public interest. As part of the decision-making process, it takes into consideration the potential environmental and social impacts and the potential for mitigation of those impacts. Mitigation measures proposed by an applicant or interested parties may be as varied as, for example, implementing a heritage resources contingency plan, re-routing a pipeline or adjusting the proposed construction schedule. The Board's mandate allows it to respond to potential impacts of a project on Aboriginal interests in a variety of ways, including accepting the impact in light of the benefits associated with the project, imposing conditions on the approval of the application to minimize the impact or denying the Application.

Since the NEB is an impartial, quasi-judicial tribunal bound by the principles of natural justice, it must receive information about Aboriginal concerns with respect to a specific project through its public hearing process. It is the practice of the Board to take Aboriginal interests and concerns into consideration before it makes any decision that could have an impact on those interests. In order to ensure that the Board has the best possible evidence before it in this respect, the Board's *Filing Manual* sets out the requisite elements of an application, requires applicants to consult with potentially impacted Aboriginal groups early on in their project planning, and requires that applications include detailed information on any issues or concerns raised by Aboriginal groups or otherwise identified by the Applicant. In addition to the initial filings required by the *Filing Manual,* the Board frequently requests additional information from applicants about potential impacts of a project on Aboriginal people and mitigation options. Typically, the stronger the Aboriginal interests and more significant the potential impact, the more evidence the Board will require before rendering its decision. Such evidence could include the details on the nature of the Aboriginal rights and interests, the efforts made by an applicant to resolve issues and the possibility of mitigation of the impacts.

In accordance with the *Filing Manual*, the Applicants in this proceeding filed the company's Aboriginal consultation protocol; provided a description of potentially affected Aboriginal groups to be consulted; identified the potential information needs of those groups; outlined the methods of and timing of its consultation; and discussed the procedure for responding to issues and concerns, plans for future consultation and follow-up throughout operations. The Applicants also described any known heritage resources in the study area and discussed the potential for any undiscovered heritage resources in the study area. The Applicants included a Heritage Resources Discovery Contingency Plan in the Application, which described what contingency plans and field measures would be undertaken should a heritage resource (including archaeological, paleontological or traditional use sites) be discovered during construction. The Applicant also provided specific information regarding impacts on vegetation, fish and fish habitat, and wildlife and wildlife habitat, which the Board recognizes can directly or indirectly impact Aboriginal interests. The Applicant's pre-application consultations with various First Nations as well as the Board's assessment of potential impacts on Aboriginal interests are described in Section 3.4 of these Reasons. In addition to the information initially filed by the Applicants, the Board asked for additional information from the Applicants as well as various Aboriginal groups who expressed interest in the matter.

Aboriginal people with an interest in a project are invited to participate in the hearing process to make the Board aware of their views and concerns. The Board has made significant efforts in the past several years to provide information to Aboriginal people so that they can understand how to become involved in the regulatory process. In addition to the information provided to the Board via the Applicant, there are numerous ways for Aboriginal people to make their views known directly to the Board. This can include a letter of comment, oral statements, written evidence, oral testimony by elders, cross-examination of the Applicant and other parties, and final argument. The Board is obligated to carry out its functions in accordance with the rules of natural justice and procedural fairness. To the extent possible and within the parameters of procedural fairness, the Board has adopted a fair and flexible process that allows Aboriginal people to provide their views and evidence to the Board.

As more fully described in section 3.4 of these Reasons, Standing Buffalo participated fully in the OH-3-2007 proceedings and offered extensive evidence of their world view and concerns about the Project. The Board is of the view that in respect of this application, Standing Buffalo was fully informed about the Project through discussions with the Applicant, the Applicants' filings and participation in the hearing and had full opportunity to voice its views and concerns to the Board in respect of the Project.

The Board's process is designed to ensure it has the best information available about Aboriginal concerns so that it may take these concerns into consideration before it renders a decision. To reiterate, the Board requires applicants to take all reasonable steps to identify and contact Aboriginal people in the area of the proposed project prior to filing their applications. This ensures that potentially affected Aboriginal people have essential information about the project and can discuss their concerns and issues with the applicant in the early planning stages of the project. Through these early discussions, an applicant can often fully or partially address the concerns of the Aboriginal people or modify the project in response to such concerns. The applicant is required to file with its application evidence related to its discussions with potentially affected Aboriginal people as well as details of the issues or concerns raised, discussed and, where applicable, resolved. The Board will typically require further information and updates from the applicant. Aboriginal people with unresolved concerns are encouraged to make their views known to the Board through some form of participation in the hearing. The Board takes all of the evidence about Aboriginal rights and interests into consideration as part of its assessment of the project impacts and determination of whether the project is in the public interest.

2.2.2 Project-Related Authorizations and Permits from other Authorities

The NEB has a primary role in energy pipeline regulation and it is the principal body through which parties opposed to or in favour of a project make their views known. There is no other government department or agency that has the ability to impose conditions on a Certificate of Public Convenience and Necessity. Other government authorities may have their own regulatory responsibilities pertaining to specific aspects of a federal pipeline. These can include federal departments such as Fisheries and Oceans or Transport Canada, as well as provincial government agencies. The process for these approvals and permits may be carried out parallel to, or independently of the NEB process and are often not relevant to the NEB decision-making process. The Board cannot be directed by other government authorities, nor does the Board have authority to direct the activities of other government authorities. Further, their decision-making responsibilities generally need not be fulfilled before the NEB makes its decision in any particular case. Those government authorities may have their own specific requirements for the issuance of their authorizations and may carry out Aboriginal consultation in respect of their decisions, where appropriate. It is the responsibility of those government authorities to ensure that they have met their legal obligations and it is a matter for the courts, not the Board, if someone wishes to challenge their process.

2.3 Conclusion

In light of the above, the Board is of the view that it has the jurisdiction to make a final determination on the applications before it and will not require the attendance of a Crown official to discuss Standing Buffalo's claim. Not only were the Applicants required to provide information to the Board regarding potential impacts of the proposed Project on Aboriginal interests including those of Standing Buffalo, Standing Buffalo participated fully in the Board's process and had the opportunity to bring all of its concerns with the Project to the Board's attention. The Board is satisfied that it has the evidence that it needs to determine Project impacts on various interests, including those of Standing Buffalo, and to determine whether the Project is in the public interest.

Accordingly, the motion is denied.

Chapter 3

Matters Common to Diluent Pipeline & Capacity Replacement Projects

3.1 Economic Feasibility, Supply and Markets

In making its determination on the justification for and economic feasibility of a proposed pipeline project, the Board assesses whether the facilities are needed and would be used at a reasonable level over their expected economic life. In order to make this determination, the Board considers the evidence submitted on the supply of commodities that will be available to be shipped on the pipeline, the availability of adequate markets to receive products delivered by the pipeline and the adequacy of existing pipeline capacity. As well, the Board considers evidence related to financing the construction and ongoing operations of the proposed pipeline.

3.1.1 Project Costs

The combined capital cost of the projects is expected to be Cdn$384 million as shown in Table 3-1.

Table 3-1
Total Direct Capital Impact of the Collective Projects[1]

	New Capital Expenditures					Line 13 Transfer
	Land	Pipeline	Pipeline Construction	Facilities	Total	
Capacity Replacement						-93.5
LSr Pipeline	$12.0	$55.0	$174.0	$56.0	298.0	
Line 2 Modifications				$42.0	42.0	
Line 13 Reversal				$44.0	44.0	+93.5
Totals	$12.0	$55.0	$174.0	142.0	384.0	0.0

1 Capital costs are summarized in Application Section 2.9 Project Costs (p.2-5), Section 4.7 (p. 4-4) and Section 5.3 (p. 5-2). Section 3.3 (p. 3-2) contains the net book value for the Transfer. These costs are estimated for the year they will be incurred and include estimated inflation. The figures are in millions of Canadian dollars

3.1.2 Ability to Finance

The Project will be financed with non-recourse third party debt and equity funding ultimately being provided by Enbridge Inc. The Applicants stated that Enbridge Inc. will source the equity funding requirements for the Project from internally generated cash flow and capital market transactions. During the initial phase of the Project, Enbridge Inc. will provide a guarantee to third party lenders in order to secure a stand-alone interim credit facility for ESL to provide debt funding until the Project has received the necessary regulatory approvals to proceed with major construction. At that time, all borrowing on the interim credit facility would be repaid by the non-recourse third party project financing credit facility and the associated guarantee from Enbridge Inc. on the interim facility would be cancelled. ESL borrowings would provide the source of debt financing for the Diluent Pipeline Project.

EPI will access third party debt raised by ESL and equity from Enbridge Inc. such that the Capacity Replacement Project would have a debt/equity ratio of 70/30 during construction and during the Interim Period. As of the closing date of the transfer of Line 13, the proceeds from the Line 13 Transfer will be offset against the then net book value of the Capacity Replacement Project, thereby completely mitigating any impact of the Capacity Replacement Project on the Canadian Mainline rate base. As well, the proceeds from the Line 13 Transfer would be used to repay all debt and equity funds raised to fund the Capacity Replacement Project, thereby completely mitigating any impact of the Capacity Replacement Project on the Canadian Mainline capital structure.

With respect to Line 13, the Applicants further advised that the revenue requirement for the first 15 years would be backed by the initial group of committed shippers. The Transportation Service Agreement (TSA) requires the shipper to maintain credit rankings at or above the following minimum credit ratings as identified in Moody’s Investor Service (Baa3), Standard and Poor’s (BBB-) and Dominion Bond Rating Service (BBB low). If a shipper’s credit ratings were to fall below an acceptable level, additional assurances and guarantees would be required.

3.1.3 Diluent Pipeline Project

The Diluent Pipeline Project would transport diluent from Chicago, Illinois to Edmonton on Line 13, an existing EPI Mainline pipeline. Line 13 would be removed from southbound crude oil service and reversed to transport diluent from Clearbrook, Minnesota to Edmonton. Line 13 would have an annual capacity of 28 600 m^3/d (180 000 bbl/d) and would provide oil sands producers with access to an abundant, low-cost diluent supply. According to the Applicants, diluent is needed to blend with heavy oil and bitumen to enable those products to be transported by pipeline.

The Applicants were of the view that the Project is an innovative solution to meeting the need for incremental diluent supply because it involved both the use of existing facilities and the construction of new facilities. As a result, according to the Applicants, not only would the Project provide cost-effective diluent transportation by virtue of the use of an existing pipeline, it would provide benefits on the crude oil transportation side.

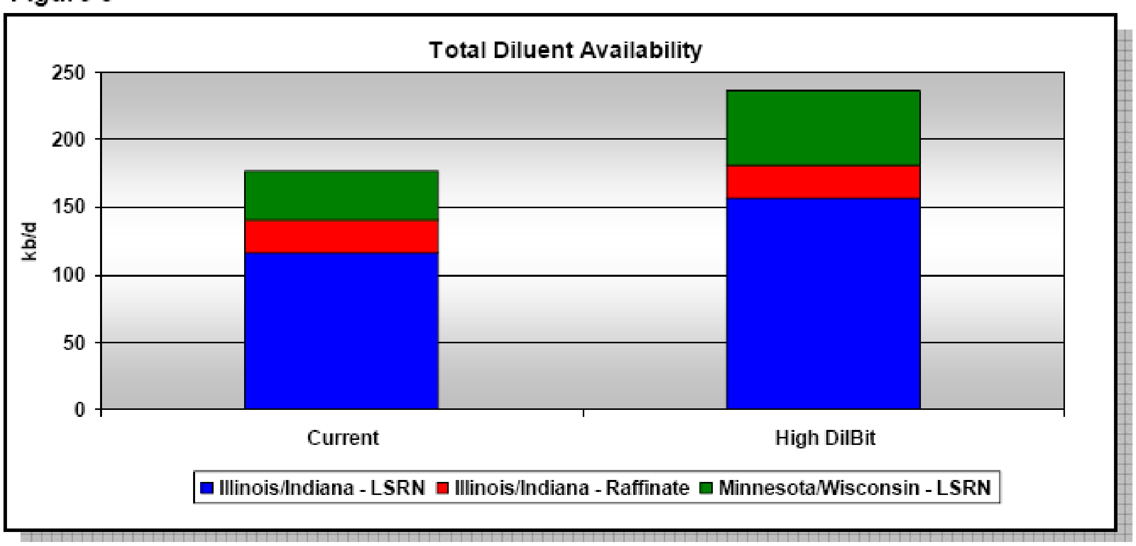
3.1.3.1 Diluent Supply

The Applicants maintained that the available diluent supply in the Chicago market is sufficient and competitively priced to be utilized in the oil sands projects. Muse Stancil was retained by the Applicants to provide an assessment of the diluent supply that could be available to the Project. It concluded that the diluent supply sources could fall into three broad categories: light hydrocarbon streams recycled from refineries; natural gasoline produced at Natural gas liquids (NGL) fractionators; and imports to North America of natural gasoline. Muse Stancil indicated that the recycled streams from refineries are expected to comprise the major source of supply to the Project.

Muse Stancil developed two scenarios for estimating the price of diluent and supply availability. In its current crude scenario, Muse Stancil indicated that the total recycled refinery supply in the Midwest would be almost 28 500 m^3/d (180 000 bbl/d). Of the total potential supply volume from Midwestern refiners of about 28 500 m^3/d (180 000 bbl/d), essentially all of this volume is blended into gasoline. In its high dilbit scenario, Muse Stancil forecasts that dilbit runs could double to 127 000 m^3/d (800 000 bbl/d) and that the potential recycled refinery diluent volume would increase to 37 300 m^3/d (235 000 bbl/d). Under this scenario, the supply of Light Straight Run Naphtha is estimated to exceed the Midwestern refiners' technical capability to blend into gasoline, by an estimated 10 300 m^3/d (65 000 bbl/d).

The Applicants were of the view that the Project does not remove hydrocarbons from the North America market, as substantially all of the volume shipped to Alberta via Southern Lights is returned to the marketplace as a component in a Canadian dilbit grade of crude. Therefore, according to the Applicants, the Project does not impose a new, incremental demand for diluent-type hydrocarbons on the North American market. In summary, the Applicants maintained that the Project is not expected to have a dramatic effect on the supply demand dynamics in North America, primarily because it does not constitute an incremental demand on the total light hydrocarbon supply in North America.

Figure 3-1
Total Diluent Availability



3.1.3.2 Diluent Market

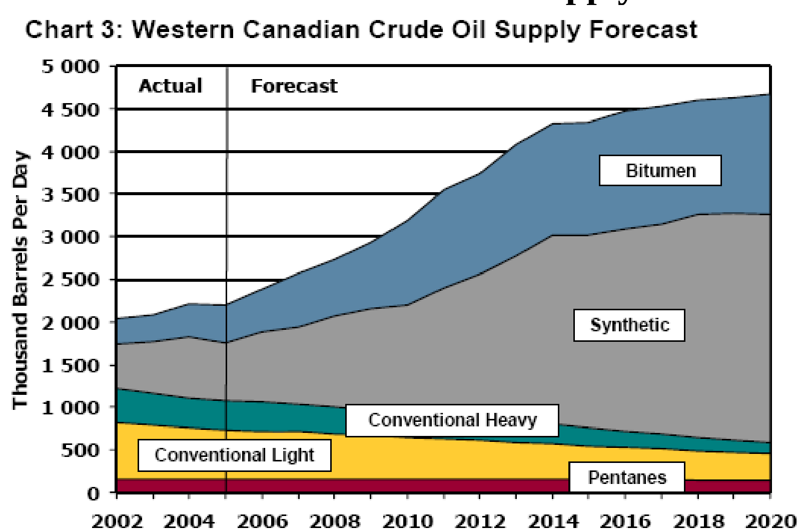
The Applicants' assessment of the diluent market took into consideration industry crude oil and local condensate production forecasts, anticipated volumes of heavy crude and raw bitumen production requiring dilution, and industry drivers for access to a new diluent supply. The Applicants also filed CAPP's *2006 Canadian Crude Oil Production and Supply Forecast.*

The Applicants identified some key points from the CAPP study including:

- EPI's forecast is similar to NEB and CAPP forecasts in identifying more than 312 000 m^3/d (1 963 000 bbl/d) of increased oil sands raw production over the next 10 years.
- Absent a pipeline importing condensate, raw bitumen supply in the synthetic bitumen (synbit) stream, net of forecast production for upgrading, grows from the 2006 estimate of 9 100 m^3/d (57 000 bbl/d) to 83 000 m^3/d (522 000 bbl/d) by 2010, increasing to 117 300 m^3/d (738 000 bbl/d) by 2015.
- CAPP forecasts declining supplies of natural gas condensates.
- Railed diluent imports into the Western Canadian Sedimentary Basin (WCSB) are increasing according to Statistics Canada.
- Imported diluent demand could range up to 35 600 m^3/d (224 000 bbl/d) by 2010 and up to 50 300 m^3/d (316 000 bbl/d) by 2015.

The Applicants were of the view that, given the above positive indicators of the potential diluent market, confirmed by firm long-term shipping commitments on the pipeline, and industry support as evidenced by the CAPP support letter, there is a strong market demand for import diluent by pipeline into the WCSB diluent market.

Figure 3-2
Western Canadian Crude Oil Supply Forecast



During the proceedings, the Applicants noted that the Line 13 Reversal does not include blending facilities as part of the Project scope. Furthermore, the Applicants stated that the blending facilities in Hardisty, Alberta and Kerrobert, Saskatchewan, where the diluent will be delivered, will be provided by connecting third parties. Although the Applicants had no further information concerning the capacity of the blending facilities in these locations, they indicated that the capacity would be largely dependant upon the amount of deliveries off the line.

3.1.4 Capacity Replacement Project

To replace the loss of southbound capacity on the EPI Mainline system resulting from the transfer of Line 13 to diluent service, the Project includes a Capacity Replacement Project that comprises the LSr Pipeline and Line 2 Modifications. The LSr Pipeline would include 288 km of new 508 mm OD (NPS 20) pipeline from Cromer to the Canada/US border near Gretna. It would have an annual capacity of 29 500 m^3/d (186 000 bbl/d). EPI indicated that there would be a loss of 11 000 m^3/d (69 300 bbl/d) of nameplate capacity out of Edmonton as a result of the Project. However, this capacity is currently not available due to system bottlenecks at Cromer. Construction of the LSr Pipeline and Line 2 Modifications would relieve the bottleneck and result in an effective increase in capacity from Edmonton to Cromer of 8 000 m^3/d (50 400 bbl/d) (70 300 m^3/d less 62 300 m^3/d).

The Line 2 Modifications and the LSr Pipeline are expected to be completed by the end of 2008. Line 13 is expected to be in diluent service in mid-2010. This would result in a period of time post-2008 where southbound crude oil capacity would increase by almost 34 800 m^3/d (220 000 bbl/d) until such time as Line 13 is taken out of southbound service. This, the Applicants argued, is another significant benefit of the Southern Lights Project as it provides additional Mainline capacity at a time when apportionment could become an issue. According to the Applicants, shippers of eastbound crude oil ex-Edmonton would realize a suite of benefits from the construction of the LSr Pipeline, including:

- a net effective increase in long-haul capacity out of Edmonton due to the elimination of Cromer injections;
- improved quality due to segregation of Cromer light sour crude volumes from Line 2 into the LSr Pipeline, and elimination of Line 2 breakout at Cromer; and
- decreased transit time due to higher flow rates and elimination of Cromer breakout.

According to the Applicants, these benefits would be realized with no cost to shippers out of Edmonton for the LSr Pipeline and Line 2 Modifications construction.

3.1.4.1 Crude Oil Supply

In support of its Application, EPI provided two forecasts for crude oil supply: CAPP's 2006 forecast and EPI's 2006 forecast. Both forecasts show significant increases in crude oil production, driven primarily by oil sands production growth over the next ten years.

With respect to Cromer receipts, EPI provided the volume and type of crude oil injected at that location. In 2007, as of April 2007, 31 000 m^3/d (195 300 bbl/d) and, in 2006, 29 100 m^3/d (183 300 bbl/d) of light sweet and sour crude oil and medium crude oil was injected at Cromer. EPI also provided a forecast of light and medium crude oil to 2015. It indicated that even with the natural decline assumed in the forecast, the 2015 LSr Pipeline annual utilization factor would remain above 85 percent. EPI maintained that, in the absence of the LSr Pipeline, crude oil received at Cromer could continue to be injected into the EPI Mainline system as is the current practice with the continuing negative impact of compromised long-haul capacity upstream of Cromer and increased potential for apportionment. According to EPI, the nearest alternative pipeline system is the EPI North Dakota system; however, this system is forecast to remain full and, despite expansion plans, would not have the capacity for volumes normally received at Cromer. EPI submitted that trucking these volumes is not considered feasible.

Table 3-2
Forecast Crude Oil Receipts at Cromer

m^3/d	2008	2009	2010	2011	2012	2013	2014	2015
Light	20 200	20 700	20 200	20 600	20 400	19 800	19 100	18 500
Medium	10 000	10 100	9 700	8 800	8 500	8 000	8 000	7 900
Total	30 200	30 800	29 900	29 400	28 900	27 800	27 100	26 400

3.1.5 Aggregate Impacts of the Project on Domestic Interests

Concerns were expressed during the hearing that if the Project were approved there would be missed opportunities or negative consequences for domestic industries, employment and security of supply.

Views of Parties

CEP contended that the Project could pose a risk to Canadian economic development by undermining investment in Canadian industries as it would predominantly be used to facilitate the export of under-refined heavy oil. As such, it would limit supplies for Canadian requirements, hinder the stimulation of investment and job creation, and decrease the degree of energy security for all Canadians, which would result in a loss of economic development and job creation in Canada.

CEP also indicated that, to the extent that imports of diluent diminish the demand for synthetic crude oil to produce synbit, increasing the supply of diluent to oil sands producers may remove or weaken an important, albeit less than ideal, domestic market for upgraded bitumen, namely synbit production.

CEP contended that if the pipeline were not approved, oil companies that wish to refine Canadian bitumen would more likely make investment decisions to do so in Canada. CEP submitted a report by Informetrica Report, which had been prepared as evidence for the Keystone application hearing. This report estimated that, in the case of the Keystone Project, domestic processing could readily represent an additional 18 000 jobs per year to the Canadian economy when compared with a scenario in which only unrefined heavy crude oil is exported to the US markets.

CEP was of the view that it would have been better to allow other market decisions to be made before a project such as Southern Lights came forward. It maintained that the wholesale export of raw materials and natural resources from Canada was not in the public interest. In CEP's view, the public interest in Canada should embrace the notion of value-added processing of Canadian resources to obtain maximum benefit. It argued that the Diluent Pipeline Project component of the Southern Lights Project was a key to the export development model because it would provide the diluent needed to facilitate the large scale export of unprocessed oil sands resources (bitumen). Furthermore, unlike other pipeline projects, the Diluent Pipeline Project had no other purpose but to prime a bitumen export looping system capable of moving 95 300 m^3/d (600 Mbbl/d) of bitumen blends to US markets.

CEP maintained that the underlying rationale for the Capacity Replacement Project was closely tied to the Diluent Pipeline Project as it sought to offset the reduction of southbound crude oil capacity on the EPI Mainline system resulting from the transfer of Line 13 to northbound diluent service. It submitted that, because it lacked an independent and clear rationale that accords with the Canadian public interest, approval of the Capacity Replacement Project should also be denied by the Board.

CEP requested that the Board deny the application either because it is contrary to the public interest, or the Applicants did not provide sufficient evidence to determine that the Project is in the public interest.

In response to CEP's position, the Applicants noted that the reversed Line 13 is not an export pipeline, rather, it would import diluent from the US to Western Canada. According to the Applicants, Line 13 would facilitate the transportation of dilbit to markets, including the US, but that transportation would occur largely through other pipelines that are independent of the Project. The Applicants pointed to the fact that the Board recently approved the Keystone Pipeline Project and found that it would not serve the Canadian public interest to deny a pipeline project for the purpose of restricting the export of bitumen so that it could be made available as feedstock for domestic upgrading projects. Such interference with the function of the market could be expected to negatively impact investment decisions and the availability of bitumen for both domestic and export users. The Applicants also argued that CEP's analysis of the potential impact of bitumen exports on domestic upgrading is wrong as CEP assumed that the amount of bitumen production would be fixed and that there would not be enough to go around. In this regard, the Applicants argued that the forecasts presented during the proceedings by CAPP and EPI are risked forecasts and assess how much domestic upgrading capacity would be developed over the forecast period. Accordingly, if more upgrading capacity is developed than forecast, bitumen production would be higher; therefore, according to the Applicants, the amount of bitumen production is not fixed.

The Applicants maintained that the Project would be an appropriate response to market forces and that Canadian energy policies are market based. It also noted that there is no government mandated upgrading or refining or continental energy market. According to the Applicants, economic efficiency comes from allowing markets to work.

The Applicants contended that there is no industry or government opposition to the Project, only opposition from labour organizations with concerns beyond the mandate of the Board.

CAPP maintained that, between the proposed in-service date of 31 December 2008 for the LSr Pipeline and the proposed completion date of 1 July 2010 for the Diluent Pipeline Project, shippers would actually receive an increase in available capacity. Furthermore, CAPP argued that this increased capacity would allow additional oil volumes to move to US markets, and producers strongly supported the addition of this capacity, especially in light of the recent apportionment experienced in the industry. CAPP strongly believed that trapped supply is not in the Canadian public interest and that there was ample evidence of substantial growth in supply during the proceeding. In its submission, CAPP stated that there was a clear market need for the Southern Lights Project and the diluent supply to Canada. CAPP added that contractual support has been demonstrated for the Project. CAPP also stated that the market is working and that there is no need for protectionism and market restriction.

Views of the Board

The Board notes that no concerns were raised in regard to financing and no parties sought to examine the Applicants on either the proposed financing or the Applicants' ability to recover the capital, operating expenses or financing costs of the applied-for facilities. The Board accepts that the Applicants have the ability to finance the construction of the Project and place it into operation. The Board notes that despite commitments of just 43 percent of available capacity, shippers have accepted contractual arrangements that cover the entire revenue requirement for the Project for 15 years. The Board is therefore of the view that adequate provisions exist for recovery of capital, operating expenses and financing costs for the applied-for facilities.

The main justification for the Project is the need for increased diluent supply for the oil sands industry to enable growth in bitumen production. The Diluent Pipeline Project would serve that need by providing access to abundant and low-cost diluent to heavy oil and oil sands producers. The Board is of the view that the Applicants' assessment of diluent supply and markets, as well as the crude oil supply forecast which supports the need for increased diluent supply, are reasonable. The Board also believes that there is ample supply to ensure that the diluent pipeline is utilized. The Board is also satisfied that there will be crude oil supply to support the long-term operation of an import diluent pipeline. In addition, the Board is of the view that there is a need for additional crude oil pipeline capacity out of the WCSB to transport growing oil sands production. In this regard, post-2008 until mid-2010, prior to the in-service date of the diluent pipeline, southbound crude oil capacity would increase.

The Board notes that the Applicants did not include the diluent blending facilities and tankage within the scope of the Project. Furthermore, the Board is mindful that the diluent market is relatively new and that there is little data available on pricing and current volumes that are used in blending to enable pipeline transportation of bitumen. Nevertheless, the Board expects that this aspect of the industry will evolve in due course and result in improved market transparency. Further, the financial commitments made by shippers demonstrate that the reversed Line 13 is required and will be used and useful as evidenced by the TSAs between ESL and diluent shippers for committed volumes on the Line 13 reversal of 77 000 bbl/d (12 200 m^3/d). The committed shippers have agreed to pay, for a term of 15 years, tolls that will recover the pipeline's total cost of service. In this regard, the Board finds that there is sufficient support for the Project.

The Board expects that the Project facilities will be useful to the functioning of the market. When assessing a facility application the Board usually considers the facility capacity relative to the apparent demand. With respect to the Diluent Pipeline Project, the Board is of the view that there is demand to increase diluent imports, albeit there is some uncertainty with respect to potential future volumes. In this case, the diluent transmission capacity is not sized to expected volumes as the Applicants proposed to reverse an existing line. Nevertheless, given the evidence on the market and supply, the Board is satisfied that the various components of the Project will be used at a reasonable level over its economic life.

The Board notes that the issue of end-of-life abandonment liability was raised during the hearing and concern was expressed with respect to the adequacy of financial reserves for these liabilities. In this regard, the Board notes that it has committed to address the issue of terminal negative salvage costs and future liability for abandonment through its recently instituted Land Matters Consultation Initiative (LMCI).[3] Like other generic proceedings that may result in industry-wide Board requirements, decisions arising from the LMCI process may impact the Project. In the interim, the Applicants must financially prepare themselves for the eventual end of the economic life of these facilities.

In regards to other domestic impacts, the Board is not persuaded crude supplies to existing Canadian refineries would be constrained as a result of the Project. Nor is it of the view that the Project will have a negative impact on job creation. The Board is of the view that there is adequate supply for existing refineries and increased movements to new markets. The Board would not be inclined to interfere in this market. In the Board's view, well-functioning markets bring about efficient outcomes that are in the public interest.

3.2 Environment and Socio-Economic Matters

The Board considers environmental and socio-economic matters under both the CEA Act and the NEB Act. The Board requires applicants to identify and consider the effects a project may have on biophysical and socio-economic elements, the mitigation to reduce those effects, the significance of any residual effects once the mitigation has been applied and enhancements of project benefits.

3 See Board Letter 3 October 2007 outlining five issues areas to be addressed.

This chapter provides a brief description of the environmental assessment process used by the NEB for the Southern Lights Project. It also addresses some socio-economic issues that were not evaluated in the ESR.

3.2.1 Environmental Screening Process

The applications made pursuant to sections 52 and 58 of the NEB Act triggered the requirement for an environmental assessment under the CEA Act. Since the Project does not require more than 75 km of new right-of-way (RoW), a screening level of assessment was conducted.

The Applicants filed an Environment and Socio-Economic Assessment (ESA) for the Project and concluded that the Project would not have a significant adverse effect on any environmental or socio-economic resources provided the mitigation measures identified in the ESA are implemented during Project construction, operation, decommissioning and abandonment.

Pursuant to the CEA Act *Regulations Respecting the Coordination by Federal Authorities of Environmental Assessment Procedures and Requirements*, the NEB coordinated RA and Federal Authority (FA) involvement in the CEA Act process. To reduce potential duplication, the Board and other RAs worked together to create an efficient screening process that would meet the needs of each in carrying out its environmental assessment responsibilities.

On 27 April 2007, the Board requested comments on the draft scope of the environmental assessment of the proposed Project from the public. After considering the comments received from the Meewasin Valley Authority and Roseau River, the Board and the other RAs for the proposed Project, Transport Canada (TC) and INAC, determined the scope of the environmental assessment on 6 June 2007.

On 13 December 2007, the Board issued a draft Environmental Screening Report (ESR) for public review and comment. The Board received comments from TC, INAC, DFO, Environment Canada, Health Canada, Manitoba Conservation, Manitoba Intergovernmental Affairs and Manitoba Water Stewardship. The Applicants subsequently filed their comments on 4 and 22 January 2008. These comments are reflected in the ESR in Appendix V of this document.

The ESR describes the Project and Project setting, identifies concerns raised by the public, specifies the methodology used by the Board in its analysis, outlines the potential environmental and socio-economic adverse effects and discusses the environmental protection and mitigation measures proposed by the Applicants. The ESR also includes recommendations for conditions to be included in any Board regulatory approvals and contains an evaluation of the likelihood of significance for any adverse effects.

3.2.2 Socio-Economic

Potential socio-economic effects covered by the CEA Act are included in the ESR. Other potential socio-economic effects covered by the NEB Act are addressed within three sections of this document: the Project's effects on employment and economics are discussed below; the Project's effects on other domestic interests are discussed in section 3.1.5; and socio-economic matters specifically related to the Capacity Replacement Pipeline Project are discussed in section 5.4.

The direct and indirect benefits of the construction phase were estimated to be Cdn$332.3 million (in 2006 dollars). This is based on an estimated $259.4 million of direct expenditures on construction, with the vast majority of the capital outlay (95 percent or $247.5 million) expected to be spent in Canada. The Applicants also submitted that using the Statistics Canada input output tables, the economic effects are expected to be an increase of $133 million in gross domestic product and employment of 1 794 person years. As well, during the construction phase, a total of $33.9 million in taxes would accrue to federal, provincial and municipal governments.

Views of the Board

With respect to its regulatory decision under the NEB Act, the Board has considered the ESR and its recommendations. The Board has determined that, with the implementation of the Applicants' environmental protection procedures and mitigation measures and the Board's regulatory requirements, including recommended conditions, the Project is not likely to cause significant adverse environmental effects.

The ESR is appended to this document and is available in the Board library or on-line at the Board's Regulatory Documents at www.neb-one.gc.ca.

In terms of socio-economic impacts not considered in the ESR, the Board is of the view that the employment and economic effects described above would be benefits arising from the Project. As outlined above, other non-ESR socio-economic impacts are considered elsewhere in these Reasons.

3.3 Public Consultation

The Board requires regulated companies to undertake an appropriate level of public involvement commensurate with the setting, as well as the nature and magnitude of each project.

This section addresses the public consultation program that was undertaken for the Southern Lights Project. The Applicants' consultation with Aboriginal people is discussed in section 3.4 and its consultation with shippers is discussed in section 4.2.4.2.

The Applicants' Consultation Program

The Applicants stated that the consultation program for the Project was based on EPI's Corporate Social Responsibility (CSR) Policy, which includes principles such as engaging stakeholders early in the development and planning process, undertaking consultation in an open and transparent manner, and maintaining ongoing dialogue with stakeholders through all project stages.

Most aspects of the Southern Lights Project consultation program were carried out jointly with the consultation program for EPI's Alberta Clipper Project, which is also subject to NEB review (Hearing Order OH-4-2007). The proposed timeline and the location of the two projects are similar so a joint consultation program was expected to improve clarity and convenience for program participants. Information was provided to stakeholders about both projects by means of correspondence, communication materials and community open house meetings. Information about the projects was provided to approximately 2 500 landowners and tenants owning or residing on land directly affected, and adjacent to, the 1 070 km RoW. In addition, people owning or residing on lands within 200 metres of the proposed RoW were informed about the proposed projects.

The Project public consultation program was initiated in September 2006 and has, to date, included a variety of activities including direct meetings with landowners and tenants, meetings with First Nations, meetings with government officials, public notices, open houses, a toll-free project message line and a Project web site. In response to issues raised by stakeholders, EPI modified the LSr Pipeline route and engaged in negotiations with landowners associations to address outstanding concerns. The issue of routing modifications is discussed in more detail in the ESR accompanying these Reasons.

Consultation Throughout the Lifecycle of the Facilities

Intervenors filed evidence with respect to their past experience with EPI regarding existing pipelines on their properties. Concerns were expressed that consultation during the operations phase of these pipelines was insufficient and that EPI did not provide adequate notice prior to entering properties to undertake repair and maintenance digs.

The Applicants have stated that consultation will continue throughout the construction and operations phases as required by EPI's CSR Policy. During the operations phase, stakeholder communications with respect to the Project facilities will be integrated into the scope of the existing Public Awareness Program conducted by EPI along the RoW.

In addition, in the Settlement Agreement between EPI and MPLA/SAPL, which was filed in these proceedings, EPI and MPLA/SAPL agreed to the formation of a Joint Committee for the Southern Lights and Alberta Clipper Projects. The terms of reference for the Joint Committee indicated that it would provide a mechanism to address systemic concerns that arise during and following construction.

With respect to issues that may arise involving landowners who are not members of MPLA/SAPL, at the oral hearing, the Applicants indicated a preference to have the Joint Committee represent both members of MPLA/SAPL and non-members. However, discussions on this matter had not taken place with MPLA/SAPL at the time of the hearing. If MPLA/SAPL were not in agreement with this approach, then the Applicants indicated that a second committee would be formed to represent non-members.

Views of the Board

The Board notes that the Applicants undertook much of the consultation for the Southern Lights and Alberta Clipper Projects jointly. The Board finds that the Applicants properly identified potentially affected stakeholders and Project impacts and used appropriate methods to engage members of the public and provide them with Project information.

The Board acknowledges concerns raised by the public about the importance of consultation throughout the operations phase of the Project and, in particular, in advance of operations and maintenance activities. The Board expects the Applicants to comply with the Board publication, *Operations and Maintenance Activities on Pipelines Regulated Under the National Energy Board Act: Requirements and Guidance*. Pursuant to section 4.3 of this publication, the Board requires regulated companies to engage parties whose rights or interests may be affected prior to undertaking operations and maintenance activities. Companies are required to document all engagement activities and maintain documentation for audit purposes.

With respect to the Settlement Agreement between EPI and MPLA/SAPL in relation to the Southern Lights and Alberta Clipper Projects, the Board expects regulated companies to conduct consultation in the early stages of project planning so that stakeholders concerns can be identified and appropriate steps can be taken to address them. In this case, the Board commends EPI and MPLA/SAPL for their efforts to engage in meaningful consultation about Project-related issues and to reach an agreement on the best avenue for their resolution.

The Board notes that 2 500 landowners and tenants were consulted and the MPLA/SAPL together represent approximately 321 landowners. For landowners who are not members of MPLA/SAPL and may have concerns arising from the Project, the Board is satisfied that the Joint Committee established by way of the Settlement Agreement, or alternatively, a second committee, could provide a useful mechanism to address issues that may arise during or after construction.

In addition to any committees contemplated by the parties, the Board has proposed a condition, should the Project be approved, requiring the Applicants to post all of their commitments on their company web site and to update that list at least quarterly. Further, the Applicants would be required to maintain detailed records of landowner complaints. The Board is of the view that these measures would facilitate ongoing dialogue between parties whose rights and interests may be affected by the Project throughout its lifecycle.

In the Board's view, the Applicants have conducted a reasonable public consultation program. Their ongoing commitment to consultation combined with the proposed conditions would continue to fulfill the requirements for consultation on the Southern Lights Project. This Panel makes no comment or finding with respect to the adequacy of the consultation program for the Alberta Clipper Project.

3.4 Impacts of the Project on Aboriginal People

Aboriginal Engagement by the Applicants

The Applicants used a 160 km corridor centred on the planned RoW (i.e., 80 km on each side) to identify Aboriginal people for consultation purposes. Initial consultation took place with First Nations whose reserves were within the corridor and with Métis organizations representing Métis communities within that corridor. In Alberta, the Applicants originally identified Métis communities represented by the Métis Nation of Alberta Region 2 and 4 First Nations. In Saskatchewan, the Applicants originally identified Métis communities represented by the Métis Nation – Saskatchewan Western Regions IA, IIA and III and Eastern Region III, and 17 First Nations. In Manitoba, the Applicants originally identified Métis represented by the Manitoba Métis Federation and eight First Nations. In addition, if Aboriginal people outside of the 160 km corridor indicated that they wished to be consulted, the Applicants engaged in consultation with those communities as well.

The Applicants' Indigenous Peoples Policy lays out key principles for relations with First Nations and Métis people. These principles include respect for traditional ways and land, heritage sites, the environment and traditional knowledge. The policy is also designed to ensure a consistent and thorough approach to consultation and engagement activities.

In October 2006, the Applicants began their first round of Aboriginal engagement with the Aboriginal people they had originally identified. This included providing Project information, requesting any consultation protocols that the communities had and discussing any potential adverse affects that could be caused by the Project.

Prior to the filing of the Project applications, the Applicants' Aboriginal engagement activities continued through a second and third round which included exchanges of correspondence and telephone calls as well as meetings with Métis organizations and First Nations.

Representatives of EPI's Aboriginal Affairs group met with INAC in 2007 to discuss the role of INAC with respect to crown consultation. Dialogue also focused on a future meeting date, which would include the participation of regional offices in Alberta, Saskatchewan and Manitoba. Future meetings were to provide an opportunity for the Applicants and INAC to better understand crown consultation on a go-forward basis, along with discussions on issues and concerns of the corridor communities. The Applicants also engaged the Manitoba Regional Office of INAC because the Project would traverse the reserve lands of the Swan Lake First Nation.

The Applicants confirmed that the Standing Buffalo reserve was located within the identified 160 km consultation corridor but was inadvertently missed in their first rounds of consultation. Contact with that First Nation did not occur until February 2007. Since that time, the Applicants have met with representatives of the Standing Buffalo.

According to the Applicants, the invitation to meet with Aboriginal people remains extended and they would appreciate a continuation of discussions. In addition, the Applicants will continue to meet with the regional offices of INAC for purposes of providing Project updates.

The Applicants confirmed that its representatives met with Peepeekisis First Nation (Peepeekisis) in accordance with the invitation outlined in the Letter of Comment from that First Nation.

Aboriginal concerns identified during the consultation activities described above included the availability of employment, training, business and contracting opportunities; potential contamination of community water supplies due to spills; prevention of pipeline ruptures; routing of the pipeline to avoid crossing reserves and Treaty Land Entitlement lands; and unsettled land claims.

The Applicants acknowledged the potential impacts on heritage resources, previously unidentified buried heritage resources and paleontological resources.

Hearing Participation by Aboriginal People

Standing Buffalo and the Dakota Nations of Manitoba intervened in the proceeding and Letters of Comment were filed by Peepeekisis and Roseau River. Standing Buffalo was the only First Nation to participate in the oral portion of the hearing, as the Dakota Nations of Manitoba subsequently withdrew their intervention. Standing Buffalo participated in the process by filing written evidence on 3 July 2007, responding to an NEB information request on 24 July 2007, leading direct evidence and cross-examining witnesses at the oral hearing.

Views of Standing Buffalo

On 3 May 2007, Standing Buffalo filed an application for intervenor status in which it cited unextinguished Aboriginal title, self-governance rights and historic allyship status as the basis for its participation in the process.

In response to an information request from the Board asking for a detailed explanation of the impacts of the proposed Project on Standing Buffalo interests, Standing Buffalo stated that the Project cuts through traditional Dakota lands, lands that are sacred and for which the Dakota people have stewardship obligations. The response also contained the submission that any building project is an interference with the land that could disrupt wildlife, harm the land and soil or disturb traditional sites and Crown land that Standing Buffalo may claim pursuant to an agreement with the Crown to replace flooded reserve lands.

Standing Buffalo provided a map that showed the Project located within the asserted traditional territory of Standing Buffalo. Elder Goodwill stated that the traditional land of the Dakota People extended through the prairie provinces and down into several states in the United States.

According to the Elders, the Dakota People were nomadic, following the buffalo herds in their migrations and accessing various resources in various locations throughout the year.

The Elders testified that consideration of the Project has shown that there are two worldviews that need to be reconciled. One, the worldview of Standing Buffalo, is holistic in its perspective and the holders of that worldview take into consideration everything before making a decision. According to the Elders, this is required because they must consider the implications for the next seven generations. The Elders indicated that the other worldview is linear and compartmentalized.

The Elders testified that the Seven Council Fires, consisting of many bands of Dakota, Lakota and Nakota, govern their People and that through the Seven Council Fires, the Dakota People had an alliance with the British Crown that existed earlier than 1776.

In addition to his testimony Elder Goodwill provided information regarding the history of the Dakota/Lakota people in his affadavit. He stated that:

> Elders tell us that the Dakota/Lakota occupied lands north of the 49th parallel well before the coming of the "white man". Most express dismay that the Crown now takes the position that this is not true.

Chief Redman stated in his written evidence that Standing Buffalo has been involved in extensive meetings with the Government of Canada and the Office of the Treaty Commissioner regarding outstanding issues concerning unextinguished Aboriginal title and governance rights of the Dakota/Lakota. Chief Redman also stated that there have been 70 meetings and yet the Government of Canada has not acknowledged its lawful obligation and continues to discriminate against Standing Buffalo regarding its lawful obligations concerning Aboriginal title, sovereign rights and allyship status by failing to resolve these outstanding issues.

Despite sending a number of letters to the Government of Canada "regarding the discussions with the Government of Canada concerning the Board interventions and how they relate to outstanding Dakota/Lakota issues," Chief Redman stated that he has received no response.

Chief Redman alleges the consultation listed in the Applicants' evidence relates to the Alida to Cromer Capacity Expansion hearing and the Applicants and Canada have failed to consult Standing Buffalo in breach of lawful obligation to the First Nation. He stated that the route of the pipeline is through traditional territories of Standing Buffalo and suggested that the Project would further limit the Crown lands that would be available to meet the terms of its flood compensation agreement and any Treaty claim. Standing Buffalo also presented evidence of a general nature as to the existence of sacred sites along the existing and proposed RoW for the Project.

Chief Redman explained that consultation from Standing Buffalo's point of view had to be inclusive of the federal government, the company proponent and the First Nations with an interest in the land. Discussions between the First Nation and the company did not amount to consultation in his view. Chief Redman took issue with the characterization of discussions between representatives of the Applicants and Standing Buffalo representatives as consultation. He also took the position that communications between Standing Buffalo and the Applicants after 13 April 2007 were made on a 'without prejudice basis' and should therefore not be raised before the Board.

When asked for advice as to how the Applicants could sit down and engage with Standing Buffalo about the Project and its impacts, Chief Redman stated:

> It would take the federal government to sit down, recognize the Dakotas that they have a lawful obligation to the Dakota people for starters and sit down and have a proper dialogue.

In response to an undertaking to the Applicants' counsel, Standing Buffalo filed a letter from the CEA Agency to Chief Redman, dated 29 June 2007 in which a representative of the CEA Agency asked whether representatives of Standing Buffalo wished to discuss the Project. The letter went on to briefly describe the Project and to advise of the NEB hearing. Chief Redman indicated that he had only received the letter about three weeks previous.

During the hearing, the Applicants and CAPP asked Standing Buffalo for further information regarding a letter received from Canada regarding its alleged claim. Chief Redman refused to respond to such questions on the basis that such correspondence was without prejudice correspondence.

Views of Peepeekisis

In a Letter of Comment dated 28 June 2007, Peepeekisis stated that the Applicants had not consulted with Peepeekisis citizens or its government. Furthermore, Peepeekisis alleged that, despite Enbridge's Corporate Social Responsibility policy which recognizes the value and importance of public consultation and stakeholder engagement, Peepeekisis was not involved in personal consultation meetings. The letter stated that methods such as project information mail-outs and public notices do not constitute consultation.

The Letter of Comment also stated that the proposed Project will run through a Treaty Four traditional and sacred burial ground, and exceed the maximum number of six inches that the Peepeekisis forefathers ceded and agreed upon in the signing of Treaty 4. Peepeekisis also noted that it did not at any time agree to the transfer of natural resources to the Province, as contained in the *Natural Resources Transfer Act* of 1930. Peepeekisis stated that there was no indication as to how First Nations peoples will directly benefit from the Project and alleged that, the Applicants and the Board in cooperation with the Provincial and Federal Governments, are in non-conformance with numerous United Nations conventions and agreements. Peepeekisis submitted that, if the Applicants' application is considered over the rights and existence of Indigenous Peoples, it is sending a message that the Board places capitalism as a priority over Aboriginal rights. The letter states that Peepeekisis people are indigenous to the land and to their environment and thus are afforded International Status and are protected under International Law.

On 28 July 2007, the Board sent a letter to Peepeekisis asking for clarification on how the proposed Project may specifically impact the Peepeekisis' interests and for any suggestions as to how those impacts might be mitigated. The Board's letter informed Peepeekisis that the Board was considering holding part of the hearing in Regina and that, even though the deadline for registering to make an oral statement had passed, Peepeekisis could ask the Board for leave to make an oral statement.

In response to the Board's letter, Peepeekisis stated that the proposed Project will run through Treaty 4 lands and that those lands were Peepeekisis's traditional lands. The response also referenced the fact that the pipeline would exceed the depth of a plough as agreed upon in Treaty 4 and the fact that, in its view, necessary Crown consultation had not occurred with respect to this Project. While the letter stated that Peepeekisis's legal counsel would respond further on the First Nation's behalf, the Board did not receive any further correspondence from Peepeekisis on the record of the Southern Lights proceeding. Given that the letter suggested that there may be some confusion as to how to participate in the Board's process, the Board sent a letter clarifying its procedures to counsel for Peepeekisis.

Views of the Dakota Nations of Manitoba

On 14 May 2007, the Dakota Nations of Manitoba filed an application for intervenor status, which included the claim that the Project would cross and impact lands that are part of the traditional territories of the five Dakota Nations of Manitoba and that the Dakota Nations of Manitoba have unextinguished Aboriginal rights including Aboriginal title and governance rights in relation to those territories. Their application for intervenor status also indicated that, to date, the Government of Canada has not formally committed to the negotiations required to deal with matters arising from the unfulfilled lawful obligations of the Government of Canada to the Dakota Nations of Manitoba and that the Government has not undertaken the necessary consultations to discharge its legal and fiduciary duty to consult the Dakota Nations of Manitoba and to meet the legal requirements of consultation and accommodation in respect of the Southern Lights pipeline or other pipelines.

By letter dated 25 July 2007, the NEB was advised by Co-Chiefs Chalmers and Whitecloud that the Dakota Nations of Manitoba were withdrawing from continued intervention in the Southern Lights applications before the Board as a result of an initial agreement reached with the Applicants. They further advised that they appreciated the positive and professional manner in which the Applicants had approached the discussions with the Dakota Nations of Manitoba. The Dakota Nations of Manitoba were optimistic that a cooperative working relationship for the future as well as substantive agreements in the longer term that would benefit their membership as well as the Applicants' pipelines would be the final result. The Chiefs commended the Applicants for their open and positive approach to the issues that were brought forward by the Dakota Nations of Manitoba and stated that they were confident that this same approach would be maintained in future discussions.

The Dakota Nations of Manitoba reiterated the concerns with respect to the Government of Canada's obligation to settle the issues that arise from unextinguished title and other related Aboriginal rights and the obligation to consult and accommodate the Dakota Nations of Manitoba who may be impacted by the proposed pipeline facilities. The Dakota Nations of Manitoba advised that discussions with the Government of Canada continue, but have not yet resulted in a final commitment in relation to the negotiation based on unextinguished Aboriginal title and rights.

The letter further stated that views on whether any legal obligations that may exist have been discharged will only be assessable in light of the outcomes that will be secured from the discussions into which the parties were then entering.

The withdrawal from the Southern Lights hearing was made on a without prejudice basis and was not to be construed as a change to the legal positions of the Dakota Nations of Manitoba previously put forward.

Views of Roseau River

In a Letter of Comment dated 1 August 2007, Roseau River broadly outlined its concerns with the Project. These included a concern that the taking up of lands and resources within Roseau River Territory for Enbridge's pipelines materially affects Roseau River's ability to obtain satisfaction of its treaty land entitlement under Treaty One. Roseau River stated that a March 1996 agreement between the First Nation and the Government of Canada recognized Roseau River's entitlement to acquire up to 16 218 acres of land in its Territory to be set aside as reserve land. According to Roseau River, only a small portion of this amount had been identified and acquired as of the date of the letter. The Letter of Comment raised concern with respect to a lack of funding support to First Nations and stated that the Crown has an obligation to engage in "meaningful consultation with respect to [identified] issues, as well as other impacts on the Roseau River Anishinabe First Nation to be identified through a properly resourced review process."

On 28 July 2007, the Board sent a letter to Roseau River asking for clarification on how the proposed Project may specifically impact Roseau River's interests and any suggestions as to how those impacts might be mitigated. The Board's letter informed Roseau River that the Board was considering holding part of the hearing in Brandon, Manitoba and that, even though the deadline for registering to make an oral statement had passed, Roseau River could ask the Board for leave to make an oral statement.

In response, Roseau River advised the Board in its 1 August 2007 letter that it had a claim against Canada with respect to reserve cut-off lands that was before the Indian Reserves Commission and that the question of the title to lands and resources within Roseau River Territory remains unsettled. Roseau River submitted that, pursuant to the March 1996 agreement, it has an established legal right to ownership of lands still to be selected, while pursuant to the unsettled claims, Roseau River has a *prima facie* case to ownership of further and additional lands. According to Roseau River, the taking up of lands for Enbridge's pipelines materially affects these established and *prima facie* rights, by altering and encumbering the land base to which the First Nation maintains legal rights and claims.

Views of the Applicants

The Applicants met with Peepeekisis' Chief, council and Elders and asked about direct impacts and any related concerns. They were not advised of any specific impact of the Project. Moreover, the Applicants stated that since this meeting, they had not heard from the Peepeekisis about any other concerns or potential impacts.

Subsequent to that meeting, the Applicants have been meeting with the member Chiefs of the Treaty One First Nations organization, which includes representatives of Roseau River and other First Nations, on the Project. The Applicants were not aware of any lands under the treaty land entitlement process along their pipeline RoW that the First Nation would consider as part of their claim process. The Applicants were also not aware of any further impacts on Aboriginal interests beyond those identified in the application or subsequent filings.

The Applicants have committed to implementing the Heritage Resources Discovery Contingency Plan in the event that previously unidentified archaeological, historical or paleontological sites are discovered during construction. Should any of these resources be discovered during construction, the Applicants have committed to suspending construction activity until they are authorized by provincial authorities to resume. If site-specific concerns are raised by Aboriginal people during consultation, attempts to resolve those concerns will be guided by the Indigenous Peoples Policy. Archaeological and paleontological investigations will be carried out and the results would be filed with the Board.

The Applicants maintained that no current traditional use of the lands along the proposed LSr Pipeline has been identified. Further, the Applicants' witnesses testified that they did not believe the Project would have any impacts on Standing Buffalo and that the existing pipeline system has been in operation for many years.

Views of the Board

The Board requires its regulated companies to consult with potentially affected people early in the planning phase of a project. This practice is essential if matters of concern to those affected are to be addressed through the design of the project.

Once an application is filed with the Board, all interested Aboriginal people have the opportunity to participate in the Board's process to ensure their views are made known and can be factored into the Board's decision-making process

In this case, the Applicants identified Métis communities and First Nations whose reserves were located within a corridor of 160 km, centred on the planned RoW. Consultation with Aboriginal people began in October 2006 and has been ongoing since that time.

Although Standing Buffalo was not identified and contacted until February 2007, the Applicants have made efforts to consult with and have met representatives of Standing Buffalo on several occasions since February and continue to seek ways to discuss the Project with that First Nation.

The Board notes the Applicants' commitment to discuss with Standing Buffalo the potential for the Project to impact sacred sites, develop a work plan and incorporate mitigation measures to address specific impacts on sacred sites into its Environmental Protection Plan. The Board would encourage Standing Buffalo to bring to the attention of the Applicants its concerns with respect to potential Project impacts on sacred sites. In light of the foregoing, the Board finds that the design of the Applicant's Aboriginal consultation program is adequate.

Standing Buffalo suggested that the Project would further limit its ability to satisfy the terms of its flood compensation agreement. Similarly, Roseau River suggested that the Project would further limit its ability to satisfy the terms of its Treaty land entitlement. The Board notes that the proposed Line 2 Modifications and Line 13 Reversal do not contemplate the acquisition of any further land as the proposed work will take place within the boundaries of existing EPI station sites. Further, the proposed LSr Pipeline involves the acquisition of only 2.17 ha of Crown land for permanent easement and would require a disposition from the appropriate authority. The remaining land required for the Project is privately held and primarily agricultural land.

The Applicants indicated that they met with the member Chiefs of the Treaty One First Nations organization, which includes Roseau River, and that, based on the information that has been provided by the First Nation, the Applicants were not aware of any lands under the treaty land entitlement process along the Southern Lights Project RoW that the First Nation would consider as part of their claims process. The Applicants committed to continue to work with the Treaty 1 First Nations organization.

The Board recognizes that the identification of traditional use sites will often require the cooperation of Aboriginal people and notes that the Applicants have committed to the implementation of a Heritage Resource Discovery Contingency Plan which includes specific procedures related to the discovery of archaeological, paleontological, historical or traditional land use sites, including the evaluation and implementation of appropriate mitigation measures. The Applicants have committed to ongoing consultation with Aboriginal people throughout the lifecycle of the Project. The Board is of the view that such consultation, which would include matters of sacred and archaeological sites, would be in the best interests of all parties. The Board is also of the view that such ongoing discussions between the Applicants and Aboriginal people, coupled with the Heritage Resource Discovery Contingency Plan would minimize potential impacts on traditional use sites, if encountered.

Recognizing the importance of archaeological resources to Aboriginal people, should a Certificate be issued for the LSr Pipeline, the Board would include a condition that directs the Applicants to immediately cease all work in the area of any archaeological discoveries and contact the responsible provincial authorities. This would ensure the protection and proper handling of any archaeological discoveries.

In terms of capacity funding, the Board notes that the Applicants submitted that they recognize that First Nations and Metis communities may have specific financial and capacity requirements in responding to the information provided to them about the Project and indicate that, where there may be a potential effect on a First Nation or Metis group, the Applicants will offer funding to assist the community in assessing such potential effects and to develop a response. The Board finds that the Applicants correctly acknowledge that engagement will vary with the circumstances and with the potential effect of the Project on the Aboriginal group.

Subsequent to their submission of Peepeekisis's Letter of Comment, the Applicants met with the Peepeekisis on July 17, 2007. During the meeting, the specific question was asked of the First Nation representatives about the direct impacts and any related concerns about the Project. The Applicants submitted that their representatives were not advised of any direct impacts and any related concerns about the Project and that Peepeekisis had not advised of additional concerns or impacts since that meeting. The Applicants committed to working with Aboriginal people throughout the Project. The Board notes that Peepeekisis did not expand upon several of the issues raised in Peepeekisis's Letter of Comment and that several of the matters raised are beyond the jurisdiction of the Board.

The Applicants indicated that they were not aware of any potential impacts on Aboriginal interests that had not been identified in the Southern Lights applications or subsequent filings. The Applicants submitted that, in the event that there are more interests that are identified that may be impacted, they would meet with the Aboriginal organization or community that has identified an interest and work with that community to jointly develop a course of action.

The Board is of the view that those Aboriginal people with an interest in the Southern Lights applications were provided with the details of the Project and were given the opportunity to make their views known to the Board in a timely manner so that they could be factored into the decision-making process.

Further, the Board is of the view that the Applicants' consultation program was effective in identifying the impacts of the Project on Aboriginal people.

The Project would involve a relatively brief window of construction, with the vast majority of the facilities being buried. As almost all the lands required for the Project are previously disturbed, are generally privately owned, are used primarily for agricultural purposes and are adjacent to an existing pipeline RoW, the Board is of the view that potential Project impacts on Aboriginal interests could be appropriately mitigated. The Board is therefore of the view that impacts on Aboriginal interests are likely to be minimal.

3.5 Project Design and Integrity

In examining pipeline and facility applications, the Board considers safety and integrity issues to ensure that companies design, construct and operate their facilities in a safe manner. The Board determines whether the proposed projects meet regulatory requirements concerning the safety of employees and the public and examines issues such as suitability of design, construction techniques, materials and control systems, as well as potential risks to pipeline integrity

The Southern Lights Project proposal has two distinct sub-projects: the Diluent Pipeline Project and the Capacity Replacement Project. The Diluent Pipeline Project involves the transfer and reversal of Line 13. The Capacity Replacement Project has two components – the LSr Pipeline and the Line 2 Modifications. Each of these two components has its own distinct engineering-related activities.

The following discusses the design and integrity issues that are common to both the Diluent Pipeline and the Capacity Replacement Projects.

3.5.1 General Design

The Line 13 Reversal consists of the flow reversal of the existing Canadian portion of the EPI Line 13 export pipeline. This pipeline currently starts at EPI's Edmonton terminal and has a Canadian terminus near Gretna. The existing 1 242 km Canadian portion of the pipeline was constructed in the 1950s and currently transports synthetic crude from Edmonton, to Clearbrook, Minnesota. ESL proposes to reverse the flow to enable the shipment of diluent, which has different flow characteristics, back to the Edmonton, terminal in Canada.

To accommodate any product that is being displaced by the Line 13 Reversal, ESL proposed a Capacity Replacement Project which has two main components: a new 288 km crude oil export pipeline called the LSr Pipeline, extending from Cromer to the United States border near Gretna; and modifications to Line 2, an existing EPI crude oil pipeline that runs from Edmonton and crosses the United States border near Gretna**.**

Drag Reducing Agent

The Applicants proposed to use a drag reducing agent (DRA) to reduce frictional pressure loss during the flow of the products being shipped on Line 2, Line 13 and the LSr Pipeline. MPLA/SAPL expressed concerns regarding the effects of DRA on the three pipelines, with respect to fouling and/or corrosion. The Applicants replied that the specific type of product proposed as DRA for the Southern Lights Project is not known to affect fouling and/or corrosion in the concentrations that would be used.

3.5.2 Standards, Regulations and Company Procedures

ESL indicated that it would adopt the most recent version of EPI's standards, specifications and procedures for the construction and operation of the Line 13 Reversal, as appropriate and applicable to the project. ESL and EPI indicated that both the Line 13 Reversal and the Capacity Replacement Projects would be designed, constructed and operated in accordance with applicable regulations and industry codes and standards, including the latest Board regulatory requirements. The Board's requirements are set out in the *Onshore Pipeline Regulations, 1999* (OPR-99), which incorporate by reference the latest Canadian Standard Association (CSA) standard Z662, *Oil and Gas Pipeline Systems* (CSA Z662). These regulations and standards in turn reference other standards that would be followed in the design.

In July 2007 an updated version of the CSA Z662 was published and the Applicants agreed that all references to CSA Z662-03 in the application for the Southern Lights Project should be replaced with CSA Z662-07 for each project phase from design to operation.

Pressure Monitoring and Management

The Applicants confirmed that both projects would comply with the overpressure control and overpressure protection requirements specified in CSA Z662-07. In addition, the Applicants indicated that they would perform and submit transient analyses to identify any operating conditions that may lead to the pipeline sustaining pressures beyond the operational limits and CSA overpressure limits. The Applicants committed to providing transient analyses for Line 2, Line 13 and the LSr Pipeline before the end of 2007.

Quality Management

The Applicants committed to implement a quality management plan to address the planning and construction of the projects. The quality management plan, consisting of a design quality management system, a materials quality management system and a construction plan, would be implemented to ensure that all applicable environmental, regulatory and statutory requirements are met, as well as to monitor and document evidence of compliance. The effectiveness of this system would be assessed through internal quality audits. The requirements and expectations for quality management and assurance that are consistent with OPR-99 would be applied to contractors, subcontractors and suppliers, as appropriate.

Integrity Management Program

The Applicants proposed to use EPI's pipeline and facility Integrity Management Program (IMP) to identify, assess and evaluate operational risks. The Applicants also indicated that the results of the integrity assessment are used to prioritize maintenance activities or projects to ensure that fitness-for-purpose tolerances are maintained. The IMP's primary goal is to prevent leaks and ruptures caused by duty-related degradation of the pipelines. The IMP includes, but is not limited to, the following specific elements:

- Corrosion Integrity Management Plan
- Cathodic Protection Program

- Crack Management Plan
- Stress Corrosion Cracking (SCC) Management Plan
- Mechanical Damage Management Plan
- In-Line Inspection Program
- Excavation Program
- Qualifications & Training Guideline

Views of the Board

The Applicants made commitments to revise or review the design of the Project. The results of the commitments to use the updated CSA version Z662-07 and to provide a transient analysis for all Project components before the end of 2007 may affect the final design of both the Line 13 Reversal and the Capacity Replacement Project. The Board requires the Applicants to comply with these commitments when developing their final design. The Board would also monitor the Applicants' compliance throughout the construction and operations phase of the Project. In addition, the Board would continue to monitor the Applicants' pipeline and facility IMP to ensure it is adequate, effective and being implemented appropriately. The Board is of the view that once the commitments are fulfilled, the pipeline design will be compliant with current standards relative to pipeline safety and integrity.

3.6 Construction and Operation

3.6.1 Construction Safety

The Applicants indicated that comprehensive health and safety plans would be developed for the construction of the Line 13 Reversal and Capacity Replacement Projects. These plans would address safety requirements, responsibilities and lines of communication during construction and commissioning. All field crews engaged on the projects would be trained and random internal audits would be carried out to ensure that personnel comply with the health, environmental and safety plan. Further, all field crews would be provided with a field handbook describing the main features of this plan.

Views of the Board

ESL and EPI would be required to file their comprehensive health and safety plans with the Board. Through onsite inspections, Board inspectors would verify compliance with these plans, regulatory requirements and the other commitments made during these proceedings. To assist Board inspectors in their activities, the Applicants would also be required by conditions to provide a detailed construction schedule and to report on a monthly basis on construction progress. This would allow Board inspectors to focus and prioritize future oversight activities.

3.6.2 Pipeline Systems Control

EPI stated that their control room operators monitor and control its pipelines and facilities through a supervisory control and data acquisition (SCADA) system. EPI indicated that its SCADA system allows operators based at the Edmonton control centre to remotely monitor and control all elements of the pipeline systems, including the pipelines, tanks, pump stations, valves and custody transfer metering. The system also monitors line pressures, flow rates, gas and fire detectors and other safety systems.

EPI indicated that it uses a real-time transient model (RTTM) computer program for leak detection. EPI's application of the RTTM is referred to as the material balance system (MBS). EPI also stated that the MBS is designed to meet current regulatory and standard requirements of OPR-99 and CSA Z662-03 Annex E, and would meet CSA Z662-07. MBS alarms are passed to the SCADA system and appear on the SCADA monitors.

Views of the Board

CSA Z662 is incorporated by reference in the Board's OPR-99. While EPI stated that its leak detection system is designed to meet the latest version of the standard, the Board notes that detailed designs are not completed. The Board would examine the transient analyses (see Section 3.5.2: Standards, Regulations and Company Procedures) and their potential impact on overall pipeline systems control, including leak detection, and detailed design components. During the Board's review, additional information may be requested.

3.6.3 Emergency Preparedness and Response

An Emergency Response Plan (ERP) is in place for all of EPI's existing pipelines and facilities between Edmonton and Gretna. EPI stated that the existing ERP contains requirements for emergency response preparedness (including equipment, training and exercises), emergency response actions (including notification, implementation of an emergency management system, safety precautions for workers and the public), and a range of containment, recovery and clean-up actions for various circumstances. The ERP includes provisions for addressing both small spills and large releases.

EPI has committed to modifying this plan to incorporate the LSr Pipeline and the Line 2 Modifications but maintained that the plan would not require modifications to address the reversal of Line 13 for diluent service.

Views of the Board

EPI's existing ERP is on file with the Board. The Board finds that the measures proposed by the Applicants to deal with emergency preparedness and response are appropriate for the scope of the proposed Projects.

3.7 Land Matters

The Board requires companies to provide a description and rationale for both permanent and temporary lands that will be required for a project in order to assess the extent of new lands to be affected by the project. In addition, companies are required to advise the Board if they are using any existing land rights or if there are areas where no new land rights are required.

The Board also requires a description of the land acquisition process as well as the status of acquisition activities. Companies are requested to provide the Board with a copy of the sample notices provided to landowners pursuant to subsection 87(1) of the NEB Act as well as all forms of the acquisition agreements. Matters pertaining to routing, lands rights and land acquisition for the Southern Lights Project are described in relation to each Project.

Diluent Pipeline Project

The Line 13 Transfer involves the transfer of existing assets and EPI's land rights within the existing Line 13 RoW. The Line 13 Reversal will include the portion of the EPI Mainline pipeline from EPI's Edmonton terminal located in the SE ¼ -5-53-23W4M, Alberta to the Canada/US border near Gretna in the SE ¼- 4-1-1 WPMMB. EPI presently holds the necessary land interests under easements for the EPI Mainline pipeline and Line 13 is located within that easement.

Under the Transfer Agreement, EPI will grant to Enbridge Southern Lights LP the licence, right and interest for the Line 13 RoW for a width of 1.5 metres on either side of the centre line of Line 13 for the purposes of operating, maintaining and repairing Line 13. Included will be the right of ingress and egress over the EPI RoW to and from Line 13.

The Line 13 Reversal would involve modifications to pumps and valves at existing pump stations on Line 13 to permit the pipeline to operate in a reverse direction. Since all of the work would occur within the existing pumping stations and valve sites on Line 13 RoW, no new land rights are required for this project. There are no routing or land concerns associated with this part of the Project.

ESL requested that the Board grant an order pursuant to section 58 of the NEB Act authorizing the construction and operation of the Line 13 Reversal facilities and exempting these facilities from the provisions of sections 30 and 31 of the NEB Act.

Capacity Replacement Project

Since all of the Line 2 Modifications would be made to existing Line 2 pipeline facilities, and as no new lands are required, there are no routing or land concerns associated with this part of the Project. No additional lands are required for the existing LSr Pipeline pumping facilities which are located at Cromer, Glenboro and Manitou. A total of 0.5 ha would be required for 12 new valve sites.

Routing of the LSr Pipeline will be located within or alongside and contiguous to the existing EPI RoW for approximately 90 percent of its 288 km length and approximately 28 km of new non-contiguous RoW will be required.

The width of the new RoW to be acquired will vary in order to create a consistent, contiguous RoW width of 36.6 m along the LSr Pipeline route.

The 28 km of new, non-contiguous RoW will deviate from the existing corridor at 11 locations to avoid wetlands, shelterbelts, burial grounds, a farmyard, a residence and existing infrastructure. The width of the RoW in these locations will be 18.3 m.

The estimated land area required for the permanent RoW and temporary workspace is approximately 377 ha and 697 ha, respectively.

In order to construct, operate and maintain the LSr Pipeline facilities, land must be acquired from private landowners and the Crown in Manitoba. EPI intends to obtain all land rights by negotiating directly with the registered owners of the land. The Applicant's land acquisition process commenced in mid-March 2007 and is expected to be completed by May 2008.

EPI maintains that it will work with landowners to apprise them of the likely impacts of construction and negotiate fair and reasonable compensation in the form of direct reclamation or monetary equivalent.

Views of the Board

The Board finds that EPI's anticipated requirements for permanent and temporary land rights are reasonable. The land rights documentation and acquisition process proposed by EPI are also acceptable to the Board. It is the Board's view that maintaining a consistent, contiguous RoW width of 36.6 meters for approximately 90 percent of the LSr Pipeline route is acceptable in order to accommodate all of the pipes within the EPI easement. Further, EPI only deviated from the existing RoW in circumstances where there would have been potential adverse effects on other land uses including those relating to the environment.

Pursuant to section 58 of the NEB Act, the Applicants are seeking an exemption from section 31 of the NEB Act which would relieve them from having to file a Plan Profile and Book of Reference (PPBoRs) in respect of the Line 13 Reversal facilities, the LSr Station Facilities and the

Line 2 Modifications. The effect of this relief would be to negate the need for the detailed route hearing process.

As the construction and installation of the Line 13 Reversal facilities, LSr Station Facilities and the Line 2 Modifications would occur at existing EPI stations and no new lands would be required, the Board finds it to be appropriate to grant the requested exemptions from filing PPBoRs in respect of those facilities.

Chapter 4

Diluent Pipeline Project

4.1 Transfer of Line 13

Line 13 is currently part of the EPI Mainline system and transports crude oil from Edmonton to the Canada/US border near Gretna. The Canadian portion of the Line 13 Transfer will include the Line 13 pipeline, the Line 13 pumping facilities, other ancillary equipment attached to the Line 13 pipeline pumping facilities, and the provision of necessary land rights associated with the Line 13 RoW and pumping facilities.

4.1.1 Operations

After the execution of the Transfer Agreement, Enbridge Southern Lights LP would engage EPI as its contract operator. As such, EPI would provide administrative, operating, and maintenance services to Enbridge Southern Lights LP in respect of the commercial operation of Line 13 including:

- pipeline operations;
- control centre;
- engineering services;
- land; and
- general and administrative.

4.1.2 Transfer Price

The Applicants seek orders pursuant to Part IV and subsection 129(1.1) of the NEB Act which are necessary to effect the transfer of Line 13 in accordance with the terms and conditions set out in the Transfer Agreement. The transfer price outlined in the Transfer Agreement is the net book value of the costs of building the LSr Pipeline and the Line 2 Modifications at the closing date of the Line 13 Transfer (proposed to be at the latest 30 June 2010) plus the cost of removing the Line 13 linefill.

The commercial arrangement underpinning the Project is that, in consideration for EPI transferring Line 13 out of EPI Mainline service, Enbridge Southern Lights LP would pay to replace its capacity with the new LSr Pipeline and the Line 2 Modifications. The *Board Oil Pipeline Uniform Accounting Regulations* (OPUAR) require that, where facilities are purchased from an affiliated company, the original cost of the facilities and accumulated depreciation is recorded in the accounts of the purchasing company. The Applicants therefore applied for the exemption, pursuant to subsection 129(1.1) of the NEB Act, from this requirement in the OPUAR. The Applicants further requested that the EPI Mainline system rate base be reduced by the transfer price such that the net book values of the LSr Pipeline and Line 2 Modifications are effectively offset in the Mainline system rate base as of the closing date rather than transferring the amount of the gain or loss from Account 31 (Accumulated Depreciation – Transportation Plant) or Account 32 (Accumulated Amortization – Transportation Plant) to Account 402 (Extraordinary Income) or to Account 422 (Extraordinary Income Deductions), as applicable and as prescribed by section 40(2) of the OPUAR.

Views of the Board

The OPUAR require that where facilities are purchased from an affiliated company, the original cost of the facilities and accumulated depreciation is recorded in the books of the purchasing company. The Board notes that none of the intervenors objected to the proposed transfer price or the sale and purchase of Line 13. As the facilities to be transferred from EPI to Enbridge Southern Lights LP would be changing from oil transportation service to diluent transportation service, the Board is of the view that it would be appropriate for Enbridge Southern Lights LP to pay to replace the annual capacity resulting from the transfer of the facilities from oil transportation to diluent transportation service.

The Board is of the view that as part of the Project, leave of the Board pursuant to section 74 for the sale and purchase of Line 13 would be in the public interest. Further the Board is of the view that the proposed methodology to determine the transfer price is reasonable, and that the Applicants may be exempted from subsection 15 (4) of the OPUAR.

The Board is of the view that it would be appropriate to reduce the EPI Mainline system rate base by the transfer price such that the net book values of the LSr Pipeline and Line 2 Modifications are effectively offset in the Mainline system rate base as of the closing date, rather than transferring the amount of the gain or loss from Account 31 (Accumulated Depreciation – Transportation Plant) or Account 32 (Accumulated Amortization – Transportation Plant) to Account 402 (Extraordinary Income) or to Account 422 (Extraordinary Income Deductions), and as applicable, as prescribed by section 40(2) of the OPUAR.

4.2 Line 13 Reversal

4.2.1 Project Design

ESL stated that the Line 13 Reversal design does not require any Mainline pipeline construction and would involve the following engineering-related works:

- modifications to the inlet and outlet piping of 16 existing Line 13 pumping facilities, which are located at existing EPI pumping stations on Line 13, to enable the reversal of flow in the pipeline;

- modification of six existing check valves;
- installation of delivery equipment and meters at the existing Line 13 pumping facilities located at the Kerrobert, Hardisty and Edmonton, pump stations;
- installation of four DRA injection facilities at the existing Line 13 pumping facilities located at the Gretna, Souris, Cromer and Hardisty pump stations;
- modification of the existing Line 13 scraper trap facilities located at the existing Kerrobert, Regina and Cromer, pump stations, as well as the existing scraper trap facility located near Kelso, Saskatchewan at Kilometre Post 899.9; and
- idling of the Line 13 pumps at the Edmonton pump station.

ESL indicated that Line 13 pre-reversal work would begin in 2009. Subject to the necessary approvals, the above-mentioned works would be completed in time for an in-service date of 30 June 2010. The Line 13 Reversal may be advanced if additional crude export capacity is available sooner.

Line Pipe

Line 13 has been owned and operated by EPI and its predecessors since it was originally constructed in 1950 with a section constructed in 1952.

Sections of Line 13 were constructed with outside pipe diameters (OD) of 406.4 mm (NPS 16), 457 mm (NPS 18) and 508 mm (NPS 20) and with wall thicknesses ranging from 7.14 mm to 8.73 mm using grades X46 and X52 pipe. Line 13 is externally coated with a coal tar coating.

ESL stated that the works associated with the reversal and re-deployment of Line 13 to diluent service would not alter Line 13's external conditions. Therefore, any imperfections or defects influenced by, or associated with, the external coating condition should not be influenced by the reversal of flow and would continue to be managed through the existing IMP.

In addition to ensuring that Line 13 is structurally sound and is fit for its new intended purpose, ESL indicated it would have to undertake engineering-related physical changes to components and facilities to enable the product to flow in the reverse direction. ESL stated that, during detailed design, a review would be conducted to re-examine the location and purpose of the six existing check valves. ESL anticipates that all of the check valves would have to be modified to accommodate the change in flow direction. In addition, ESL stated that the review may identify that some check valves may have to be relocated depending on their purpose. If the check valves are in good condition, they would be reused in accordance with CSA Z662 requirements. If the existing valves are not in good condition or do not meet CSA Z662 requirements, they would be replaced with new check valves. In addition, modification to existing scraper traps to accommodate the latest in-line inspection tool models would be undertaken.

Pumping Facilities

Other engineering-related physical works associated with the change in product flow direction include the reversal of the inlet and outlet piping at the existing 16 Line 13 pumping stations identified in the application. Delivery facilities and metering would be installed at three stations and DRA units would be installed at four existing pump stations.

4.2.2 Integrity

Following the acquisition of Line 13 by ESL, the pipeline would remain operated, controlled and monitored by EPI. Enbridge Southern Lights LP would contract with EPI for Line 13 to be operated pursuant to the existing EPI standards and programs, which include the IMP (described in section 3.5.2).

4.2.2.1 Operational and Integrity Management History of Line 13

Since its construction in the early 1950s, sections of Line 13 have undergone various reconfiguration phases and have operated in refined products service as well as in crude oil service. The pipeline currently includes line pipe sections of different specifications and pipe manufacture and is in synthetic crude oil service. The original pipe joints were fabricated using flash welded or electric resistance welded (ERW) processes. Pre-1970s ERW welds were susceptible to flaws such as non-metallic inclusions, lack of fusion, low toughness and hook cracks.

In 1993 and 1994, hydrostatic pressure tests were conducted in order to obtain Board approval for increasing the maximum operating pressures (MOP) on segments of Line 13 between Regina and Gretna. Several test failures occurred and were confirmed to be caused by long seam defects that had not grown during historical operations, but failed when subjected to higher pressures than the defects had ever experienced.

In 2002, an in-service leak occurred on the Regina to Gretna segment due to a hook crack that survived the 1993 and 1994 tests. A metallurgical analysis concluded that the original hook crack, introduced during pipe manufacture, had extended by a fatigue growth mechanism. As explained in the reports dated 2003 and filed in these proceedings, the operational changes associated with the 1990's pipeline expansion program rendered the existing Line 13 imperfections susceptible to pressure cycle-induced fatigue. Subsequently, pre-existing non-injurious pipe manufacturing flaws that withstood the 1993 and 1994 hydrotests could potentially grow until failure.

Management of Crack Features

EPI implemented a crack in-line inspection (ILI) program for Line 13 in 2003, using the GE PII ultrasonic crack detection (USCD) tool. EPI submitted that the USCD tool is capable of accurately locating and sizing long seam defects to allow for targeted repairs consistent with CSA Z662 requirements. EPI specified that, at this time, one set of inspections with the USCD tool has been completed on the Kerrobert to Gretna (comprising Regina to Gretna) portion of Line 13, while the remaining Edmonton to Kerrobert portion is scheduled for 2008.

The Board requested clarification that there were no other crack features, such as SCC or cracking in dents, that pose significant integrity risks on Line 13. The Applicants indicated the pipeline is externally coated with coal tar which has historically performed very well at protecting it from external corrosion damage, and EPI qualified the SCC threat as low. Since approximately 1996, EPI has monitored the entire Line 13 for SCC. No SCC was reported through field non-destructive examinations (NDE) performed on Line 13 or through other maintenance activities where a crack ILI had been conducted. With respect to cracking in dents, EPI noted that a failure due to a cracked dent is unlikely given Line 13's operational history. If warranted by future information gathered through integrity excavations for example, the Applicants committed to apply future new inspection tools capable of detecting dents with secondary features.

EPI confirmed that the primary cracking threat on Line 13 is fatigue crack growth of existing manufacturing flaws. EPI analyzes pressure cycling data on a quarterly basis in order to predict the fatigue life of cracks and estimated that any existing crack would not fail within 20 years. Future crack re-inspection intervals were therefore conservatively set at 10 years, subject to an annual re-evaluation.

Management of Corrosion and Geometry Features

The Applicants submitted that corrosion features are primarily prevented through Line 13's external coal tar coating or recoats with high integrity coatings, which are supplemented by the cathodic protection system. Defects are monitored through excavation findings and regular metal loss ILIs since 1972. Regarding geometry features such as dents, the entire pipeline has been examined by specific ILIs, and EPI is in the process of completing excavations related to the latest tool inspections dated 2006. The Applicants also committed to providing the comparison between field findings and geometry ILI data.

4.2.2.2 Impact of Line 13 Reversal Project on Pipeline Integrity

Revised Pressure Profiles

The reversal of flow for diluent service on Line 13 requires the reversal of pumps. Typically, pipeline segments that are currently upstream of pump stations and that underwent relatively low suction pressures would become located downstream of pumps and would undergo higher discharge pressures.

The Applicants anticipate that segments immediately upstream of Langbank, Saskatchewan, Glenboro, and Gretna would be subjected to operating pressures averaging eight times their current and historical operating values. Nevertheless, the proposed operating pressures would remain within the MOP currently approved.

Diluent Service

According to the Applicants, Line 13 materials and components are designed for low vapour pressure (LVP) hydrocarbon liquids and, to date, the pipeline sections have transported refined products, crude oil and synthetic crude oil. The diluent to be shipped on Line 13 would consist of natural gasoline or light hydrocarbon streams recycled from refineries. ESL confirmed that its diluent specifications and pipeline operating parameters, such as temperature and pressure, would ensure that Line 13 remains in LVP service with all transported products in liquid phase.

Further, the Applicants indicated that the flow rate, temperature and type of product being shipped would not significantly change after reversal of Line 13. Therefore, the rate of corrosion is not expected to impact metal loss ILI intervals.

4.2.2.3 Assessment and Validation of Pipeline Integrity

Engineering Assessments Before and After Reversal

The application did not include an engineering assessment (EA) on the reversal of Line 13; nor did it include a commitment to perform one. The Applicants submitted that preliminary EA work had begun and estimated that post-reversal pressure cycles would be less severe than with current Line 13 service. The Applicants stated that final calculations related to crack growth rates require actual pressure profiles and pressure cycle data in order to verify preliminary estimates in a final EA post-reversal. They proposed to finalize and submit an EA related to crack growth rates when Line 13 would be reversed and new pressure profiles with pressure cycle data become available. The Applicants added that crack growth rates have no immediate impact on pipeline integrity and that their current Line 13 fatigue assessment is believed to be a generally conservative estimate of post-reversal conditions.

Potential Requirement to Hydrotest

The Applicants considered the need for hydrostatic pressure testing but determined that hydrotesting was not required. This decision was based upon future operating pressures not exceeding the existing MOP and the ILI program implemented on Line 13.

EPI reported that its use of ILI technology to manage pipeline integrity and reduce the likelihood of failures has been successful. Given EPI's most recent experience on 32 km of Line 3 downstream of Hardisty, the USCD tool was accurate in finding all defects that would have otherwise failed below the hydrostatic test pressure. According to the Applicants, this crack inspection device also has the ability to detect near-critical features that would not fail during a hydrotest but that could become injurious with time. However, the Applicants acknowledged that the probability of detection (POD) of the USCD tool is not 100 percent (the vendor specifies 95 percent); nor is it 100 percent accurate in sizing defects. The Applicants committed to provide the results of the USCD tool's reliability analysis as part of the first EA required by the Board.

The Board proposed that an approval for the Line 13 Reversal require the Applicants to hydrotest all, or portions of Line 13, should the filed EA insufficiently demonstrate that the pipeline may safely commence operation in diluent service. The Applicants commented that other options such as additional non-destructive tests, inspections or investigations should not be precluded.

Views of the Board

The Board expects that ESL will be informed of EPI's historical and ongoing experience with Line 13 operations and integrity activities for the purpose of ensuring the integrity and safe operation of Line 13. Both companies committed to following OPR-99 and CSA Z662-07 requirements and to adopt EPI's existing IMP.

The Board notes that clause 10.14.2.2 of CSA Z662-07 addresses the integrity of existing pipeline systems and states:

> Where the operating company intends to operate the pipeline system at a pressure that is significantly higher than the established operating pressure, and which can therefore lead to failures in the pipeline system, it shall conduct an engineering assessment to determine which portions can be susceptible to failures and whether such portions are suitable for the intended operating pressure.
>
> Note: For example, when the operating company intends to increase the operating pressure of a pipeline system that has historically operated well below its maximum operating pressure, such an engineering assessment is required.

In addition, clauses 10.14.2.3 and 10.14.6.4 of CSA Z662-07 state that pressure testing may be necessary where the EA indicates that portions of the pipeline system are susceptible to failures or where information is unavailable to complete the EA.

The Board recognizes that EPI has implemented corrective actions and no occurrence of line pipe failure has been reported on Line 13 since the 2002 leak. However, the presence of long seam manufacturing flaws susceptible to pressure cycle-induced fatigue growth remains a concern due to the lack of data provided to the Board relative to this integrity hazard. The Board also considered the pipeline's condition, the historical experience gained after numerous hydrotest failures and the recognition that the expansion program in the 1990s has rendered sections of Line 13 susceptible to fatigue cracking. Further, given the current lack of available data and as the proposed diluent service consists of a reversal of flow, where some pipe sections would be subjected to average operating pressures nearly eight times as high as historical pressures, the Board is of the view that even if current MOP levels are respected, an EA is necessary in accordance with clause 10.14.2.2 of CSA Z662-07.

As a result, the Board would require the Applicants to file an EA at least nine months prior to the Line 13 Reversal in order to confirm ongoing pipeline integrity. Should information be unavailable or of limited reliability and therefore require substitutive information, the Applicants may conduct additional non-destructive tests, inspections or investigations in advance of filing the EA and eventually propose subsequent options for the Board's consideration. Nonetheless, sufficient information must be provided no later than nine months prior to reversal in order for the Board to determine the suitability of Line 13 to operate in diluent service. The Board requires such assurance by that date in order to avoid mutual time constraints in the event that hydrotesting would be contemplated. As outlined in the proposed conditions, the Applicants would be required to hydrotest all, or portions of Line 13, should the Board determine that the EA does not adequately address its concerns.

The Board is cognizant that the improved capabilities of high-resolution ILI tools enable pipeline companies to optimize the scheduling of inspection and repair intervals. The Applicants' reliance and ongoing confidence in ILI technology is noted, but the Board cautions that marginal inaccuracies associated with a POD of 95 percent for the USCD tool may become significant. Furthermore, portions along the 1 242 km of Line 13 have only undergone one USCD tool run to date, while no crack ILI will have been performed on the remaining portions (which approximate half of the Line 13 length) until 2008. The Board would require the Applicants to demonstrate that they possess sufficient validated data on crack locations, sizes and growth rates along the entire pipeline. Additionally, the Board reminds the Applicants of their commitment to include in the EA an analysis of the USCD tool's reliability, as well as the comparison between geometry ILI data gathered in 2006 and excavation findings, specifically regarding potential cracked dents. The Board refers the Applicants to the American Petroleum Institute standard (API) 1163, *In-line Inspection Systems Qualification Standard* (or another analogous standard) for guidance on the qualification of the ILI process and results.

The initial EA would be revised no later than six months after reversal of flow. The revised EA shall incorporate actual operating data of Line 13 in diluent service to adjust estimated defect growth rates and ILI intervals as necessary.

4.2.3 Construction and Operation

4.2.3.1 Joining Programs

The modifications to Line 13 may require welding on liquid-filled piping. If welding occurs on liquid-filled pipeline components with a carbon equivalent (CE) greater than 0.50 percent, then according to subsection 38(3) of the OPR-99, the company is required to submit the welding specifications and procedures and the results of the procedure qualification tests to the Board for approval.

Views of the Board

The Board requests and reviews the joining programs when welding on materials with a CE greater than 0.50 percent is performed to verify that appropriate welding procedures are employed in order to prevent cold cracking in steels with high CEs. The potential for delayed hydrogen cracking increases proportionally with the CE of the base materials to be joined. This effect may be compounded by the quenching effects of flowing liquids within the pipeline on weld deposits placed on the surface of in-service pipelines. Accordingly, the Board requires that the joining programs for the Line 13 Reversal be filed with the Board.

4.2.3.2 Leave to Open Exemption for Line 13 Reversal Facilities

ESL requested that the Board grant an order pursuant to section 58 of the NEB Act authorizing the construction and operation of the Line 13 Reversal facilities and exempting these facilities from the provisions of sections 30 and 47 of the NEB Act.

4.2.3.3 Line Fill Removal and Diluent Line Fill

ESL and EPI indicated that they would jointly develop a plan for the removal of the line fill currently in Line 13. They stated that this plan would provide for an efficient and cost-effective manner to relocate EPI's line fill from Line 13 and to other EPI facilities. EPI committed to provide the line fill removal plan to the Board before its implementation.

Upon the completion of necessary construction and start-up activities to facilitate the delivery of diluent, ESL would commence filling the reversed Line 13 with diluent supplied by ESL's shippers in accordance with the TSA. ESL would consult with its shippers to reach agreement on provision of diluent line fill in a timely and cost-effective manner (Diluent Line Fill Plan). Before commencing line fill activities, ESL also committed to advise the Board of the Diluent Line Fill Plan.

Views of the Board

EPI will design the Line 13 Reversal facilities in accordance with OPR-99 and CSA Z662-07. During construction, Board inspectors would verify EPI's implementation of its designs and the quality control provided. Through its construction oversight, the Board will monitor construction and commissioning to ensure that standards are met. The Board finds EPI's commitment to submit its line fill removal plan and its Diluent Line Fill Plan before implementation satisfactory. In light of these measures the Board is satisfied that the Line 13 Reversal Project facilities could be safely opened for transmission and that no requirement for a leave to open order would be required.

4.2.3.4 Emergency Preparedness and Response

ESL stated that EPI's existing ERP includes emergency response resources, environmental sensitivities and control points that have been specifically identified for Line 13. ESL further stated that all aspects of their ERP would be applicable for a pipeline transporting diluent and no additional measures would be required.

Several interested groups expressed concerns about the crossing of the South Saskatchewan River. Concerns were raised over the ability of the Applicants' staff to reach the South Saskatchewan River pipeline crossing in a timely manner in the event of a spill or leak. They also expressed concern with how emergency measures are coordinated with local authorities downstream and the quantity of hydrocarbons that could enter the South Saskatchewan River before the pipeline was shut down. Interested groups had particular concerns about the threat of a spill or leak on drinking water and recreational use of the river downstream of the crossing.

ESL committed to meeting with the Board after the pipeline reversal has taken place and the pipeline is in operation, to discuss its emergency response plans in relation to the South Saskatchewan River.

> ***Views of the Board***
>
> The Board considers it prudent for ESL to conduct an emergency response exercise at this river crossing. The Board would require ESL to conduct the exercise within six months of the pipeline being placed in service and to report the results to the Board.
>
> The Board also intends to meet with ESL to discuss ESL's emergency response program as it relates to the South Saskatchewan River crossing when the pipeline is operational.

4.2.4 Part IV Matters

4.2.4.1 Appropriateness of Contracted Capacity on Common Carrier Pipeline

Subsection 71(1) of the NEB Act requires that an oil pipeline company offer service to any party wishing to ship oil on its pipeline. Where capacity on an oil pipeline is contracted, the Board examines the open season process and the capacity to be made available for spot shipments in considering whether the pipeline is acting in a manner consistent with its common carrier obligations.

4.2.4.2 Open Season and Available Capacity

EPI advised that during its first open season, it received commitments exceeding the planned 28 600 m^3/d (180 000 bbl/d) capacity for the diluent pipeline. Committed shippers were prorated to an aggregate maximum of 25 740 m^3/d (162 000 bbl/d) to retain a portion of the capacity for spot shippers. Subsequently, there were terminations of commitments totalling 13 506 m^3/d (85 000 bbl/d), resulting in committed volumes totalling 12 234 m^3/d (77 000 bbl/d).

A second open season, which was directly communicated to 32 companies including all companies that had previously expressed an interest in the Project, was offered on similar terms and conditions with no further shipper commitments. The only term offered was for 15 years. ESL foresees that future open seasons, with somewhat similar terms and conditions to the existing TSA, are possible. The term would be for the remainder of the 15-year term undertaken by current committed shippers and there would be some adjustments to the proposed TSAs given that certain termination clauses would no longer be relevant. ESL also noted that the current committed shippers have a right of first refusal on any of the capacity to be offered in a future open season.

Views of the Board

In concept, the Board is not opposed to combinations of contracted capacity on common carrier pipelines. In previous decisions, the Board has found that an oil pipeline acts in a manner consistent with its common carrier obligations when an open season is properly conducted and where the facilities are either readily expandable or capacity is left available for monthly nominations. In this case, the Board is satisfied that the open season conducted granted all potential shippers a fair and equal opportunity to participate.

With respect to the holding of another open season, the Board notes that ESL has provided its committed shippers with the right of first refusal should another open season be contemplated. The Board notes that, during the hearing, no potential shipper came forward to indicate a firm intention to ship on an ongoing basis, nor was any view expressed disputing the fairness of ESL giving its committed shippers the right of first refusal.

4.2.4.3 Method of Regulation

For the purpose of toll and tariff regulation, ESL requested that it be regulated as a Group 2 company on a complaint basis, provided that Group 2 status would not prevent the Board from approving its toll and tariff principles. If that outcome were not possible, ESL requested Group 1 status along with approval of its tolling principles and tariff. ESL stated that there was no industry-wide negotiation, but rather the toll principles and the tariff were the product of negotiation between ESL and those committed shippers that signed the TSA.

Views of the Board

When determining whether a company should be designated as Group 1 or Group 2, the Board has previously considered the size of the facilities, whether transportation services are provided for third parties, and whether the pipeline is regulated under the traditional cost of service methodology. Given that the toll principles have been negotiated with ESL's committed shippers and that there is only one line and one product being shipped, the Board has concluded that ESL should be designated as a Group 2 company. ESL is therefore required to comply with the requirements of subsection 5(2) of the OPUAR and all toll filings pursuant to 60(1)(a) of the NEB Act shall be accompanied with supporting documentation for the tolls.

The Project contains the first diluent line to be regulated by the Board. As such, the Board is of the view that additional regulatory oversight is appropriate to ensure that all shippers that nominate volumes to the line are granted reasonable access and that the premium in the toll for uncommitted volumes does not become an unreasonable impediment to potential spot shippers. Therefore, the Board directs ESL to file information outlining the transported diluent volumes, including volume and revenue from diluent shipments. This quarterly information is to be reported separately for both committed and uncommitted shipments and is to be filed annually. This information is to be filed for a trial period of the first five years of Line 13 operation. The Board also directs ESL to annually file summary information on new requests for committed service. The information filed is to include the number of requests, volumes and number of shippers. If disputes arise respecting the tolls charged or the term of access to, or transportation on, the pipeline, all shippers whether having signed long-term TSAs or not, would have the right to complain to the Board.

The Board also notes that, while the diluent market is expected to evolve, there is always some possibility of participation by affiliates of the regulated pipeline entity. To ensure that such participation does not trigger conflict of interest concerns, the Board directs that ESL file for approval of a Code of Conduct at least 60 days prior to the operation of the reversed Line 13, addressing the following matters:

- mitigation of market power and promoting fair competition;
- prevention of unduly preferential treatment;
- prevention of cross-subsidization;
- transfer pricing;
- governance of separation of business;
  - sharing of employees and other resources;
  - separate operations and financial;
  - separate management;
  - physical separation;
- confidentiality;
- compliance plan, audit and penalties;
- dispute resolution, and
- regulatory oversight.

4.2.4.4 Toll Principles

ESL sought approval, under Part IV of the NEB Act, of the tolling methodology that will be used to establish the tolls for the reversed Line 13 in accordance with the terms and procedures detailed in the toll principles in the TSA. ESL and the committed shippers have contractually agreed on a method to calculate the tolls. ESL stated that the toll principles agreed to by the committed shippers are an essential element of the contractual relationship between itself and the committed shippers in order to provide a level of certainty in respect of tolls to be charged over the initial 15 years of the Line 13 Reversal.

ESL proposed to offer two types of service on the reversed Line 13. The first type of service is for committed shippers, those who have executed a TSA and provides for the transportation of a stated daily volume for an initial term of 180 calendar months. The second class of service, 'uncommitted', is for shippers that have not entered into a TSA or for those committed shippers that wish to transport volumes in excess of the committed volumes as agreed in the TSA. The proposed toll for the second class of service will be at least equal to twice the committed toll.

In general, the toll principles provide for tolls to be established on a full cost of service basis. Tolls for any calendar year would be subject to an adjustment to be made after the year end of such calendar year to reflect differences between the estimated cost of service and the actual cost of service, revenue from uncommitted tolls and power savings for volumes of diluent that are not transported all the way to Edmonton, Alberta.

The key toll principles include the following main points:

- General:
  - cost of service methodology
  - a true-up of certain elements of the revenue requirement in the year following
  - a ratio of tolls for uncommitted volumes to those of committed volumes, no less than two times.
- Rate base:
  - to include capital costs and Allowance for Funds Used During Construction related to acquiring and transferring Line 13, all costs associated with the Line 13 Reversal, and all development costs associated with the Line 13 Reversal and the Capacity Replacement costs
- Return on rate base:
  - deemed capital structure of 70 percent debt and 30 percent equity
  - a nominal return on equity between 10 percent and 14 percent depending on the variance between actual capital costs and the September 2006 estimate
- Income tax allowance:
  - income tax allowance as if ESL were a stand-alone pipeline transmission company on flow-through basis
- Revenue includes (among other items):
  - 100 percent of revenues received by carrier from transporting uncommitted volumes, if volumes are less than 23 800 m^3/d (150 000 bbl/d)
  - 75 percent of revenues received by carrier from transporting uncommitted volumes, if volumes are more than 23 800 m^3/d (150 000 bbl/d)

The Applicants stated that the proposed transfer price of Line 13 ensures that there is no net change to the Canadian Mainline rate base and the capital structure. The Applicants further stated that there would be efficiency gains for the Mainline shippers through the transfer of Line 13 and EPI's role in the ongoing operations of the diluent line and through the incremental revenue from the alternative use of Line 2 breakout tankage at Cromer.

Other features not listed as key principles include the right of first refusal to current committed shippers in the case of a future request for an open season.

ESL filed evidence of Kathleen McShane of Foster Associates (McShane) in support of the reasonableness of using a deemed common equity ratio of 30 percent and a base common equity return of 12.0 percent.

Ms. McShane identified the following specific strengths of the Southern Lights Project:

- the 15-year term of the TSAs;
- the cost of service methodology limiting the pipeline's exposure to cost and volume risk over the term of the TSA;
- creditworthiness of committed shippers; and
- strong economic fundamentals of the oil sands development.

The specific risks or weaknesses of the project were cited as:

- beyond the 15-year term of the TSAs, the pipeline will retain volume risk;
- the equity return will be locked in for 15 years; and
- equity investors are taking some risk, for example fisk of the following:
    - construction costs overruns; and
    - development costs, if the project does not proceed.

Ms. McShane provided an estimate of the appropriate range for returns on equity for comparable risk. This evidence submitted comparisons with returns on other NEB-regulated pipelines (Trans Mountain Pipeline, Trans-Northern, Maritimes and Northeast Pipelines, Alliance, Brunswick and the proposals for the Mackenzie Valley pipelines.) Ms. McShane acknowledged that several of the comparables are negotiated returns and that those are more likely to be higher than the application of results from the Board's return on equity formula.

ESL also requested that the Board approve its diluent tariff. This tariff addresses items that are contained on a liquids pipeline tariff, including quality specifications, equalization adjustments, tenders and nominations, and payments and carrier's lien.

Views of the Board

The Board notes that the toll principles and diluent tariff were the result of agreements with ESL's committed shippers. During the hearing, no intervenor objected to the tolling principles. The Board is of the view that the negotiation process is a give and take process in which a party might give on an otherwise important issue to gain a favourable overall outcome. The Board, therefore, accepts the proposed toll principles and tariff as a package. Accordingly, the Board approves the applied for toll principles and tariff for the Line 13 Reversal.

As a common carrier, ESL must continue to provide service with reasonable terms and conditions. The common carrier obligation was discussed in detail in the Board's Reasons for Decision in MH-4-96 addressing Pan Canadian Petroleum Limited's Request for Service, wherein the Board noted that a series of commercial and regulatory decisions over many years had led to the development of physical and regulatory impediments to access for NGL to the lowest cost system. In the course of ruling on the specific access request that was the subject of the application, the Board commented at page 14:

> While the Board's decision in this case is intended to alleviate the immediate obstacles faced by PanCanadian, which seeks to become a new shipper of record of NGL, the Board considers that, over time, others may wish to obtain the same, or similar, rights in order to compete effectively in the NGL market. In this connection, the Board has a responsibility to ensure that conditions of access to oil or other pipelines facilitate the operation of broad market forces here as in other parts of the hydrocarbon sector of the economy and that the most efficient and effective energy transportation services are available to all potential shippers of NGL.

The Board is of the view that it has a similar responsibility in this case and will therefore monitor the application of the approved toll principles to ensure that they will continue to result in just and reasonable tolls.

Chapter 5

Capacity Replacement Project

5.1 Project Design

The following describes the overall engineering-related works and issues associated with the two components of the Capacity Replacement Project.

5.1.1 Line 2 Modifications

This component of the Capacity Replacement Project does not require any new pipeline construction or modifications to the existing 610 mm (NPS 24) OD 1950s-era Line 2 pipe, pipeline valves or scraper facilities. The project consists of modifications to Line 2 to increase the annual capacity to 70 300 m^3/d by adding DRA injection units at specific existing Line 2 pump stations. In addition, the Line 2 Modifications includes pump and motor modifications and replacements at selected Line 2 pumping facilities.

After performing a hydraulic analysis of the entire length of Line 2 to determine the optimum combination of pump horsepower and DRA injection units that would achieve the desired capacity of 70 300 m^3/d, EPI determined that it would have to perform modifications at all 22 pump units on the Canadian pipeline section. The modifications vary from new pumps, pump replacements or modifications to obtain the desired horsepower. In addition, the hydraulic analysis recommended the addition, re-commissioning or relocation of DRA injection units. The proposed work at each pump station is highlighted in Table 3-4 of Appendix 5-1 of the application.

EPI stated that the hydraulic design assumed that the maximum discharge pressures from each pumping facility would be limited to the maximum discharge pressures currently set by EPI in each section of Line 2. EPI also stated that these discharge pressures are lower than the Line 2 current MOP.

Construction of the Line 2 Modifications would begin in early 2008, for a target in-service date of 30 September 2008.

5.1.2 LSr Pipeline

The LSr Pipeline's design would include approximately 288 km of new pipe with related components and associated facilities. EPI stated that the pipeline would require the construction of new pump units at three existing EPI pump stations located at Cromer, Glenboro and Manitou. These new pumping facilities would be located separately from the existing EPI pumping facilities, but on existing EPI pump station sites. The pipeline would be designed to transport crude oil and would be operated as a LVP. EPI indicated that it would comply with the applicable code requirements for minimum depth of cover.

EPI intends to start construction of the LSr Pipeline in the beginning of August 2008, although pump station work would commence earlier. The planned in-service date is 31 December 2008.

Line Pipe Design

In its application, EPI indicated that the pipe for the LSr Pipeline would be Grade 483 (X70) steel and would be manufactured using either a longitudinal or helical seam welding process in compliance with CSA Z245.1 or API 5L pipe manufacturing standards. As indicated in Table 2-4 of Appendix 5-1 of the application, the pipe would be 508 mm OD and would have a wall thickness of 6.4 and 6.7 mm except at uncased railway crossings where it would be 10.2 mm.

EPI filed engineering updates for the LSr Pipeline which revised Section 2.3.2 and Table 2-4 of Appendix 5-1 of the application. In these updates, EPI stated it would install a section of Grade 550 (X80) line pipe with equivalent wall thickness to the proposed Grade 483 (X70) line pipe to refine welding and handling techniques. The revised Table 2-4 shows that the entire pipe would be 6.4 mm thick, except for uncased railway crossings which would be 10.2 mm thick.

EPI stated that the pipeline would contain short lengths of heavy-wall pipe, which are required for crossings of roads and major rivers. The length and wall thicknesses of these additional heavy-wall segments would be determined based on engineering assessments performed during detailed design.

EPI chose not to use 6.7 mm thick pipe for the first 24.2 km downstream of the Cromer station where an MOP of 10 200 kPa was initially applied for. The revised Table 2-4 indicates that the anticipated pressure along the entire length of the LSr Pipeline would now be 9 650 kPa. The revised table also highlights the required pump power needed for all three stations.

Coating

EPI indicated that the primary corrosion control would be provided by a plant-applied fusion bond epoxy coating. At locations where damage to the coating may be encountered during crossings or construction, EPI may apply an additional abrasive resistant coating or use other coatings such as rock shield, sand padding or concrete coating. Consistent with current pipeline design, EPI indicated that a cathodic protection system would be used as a secondary corrosion control measure.

Hydrostatic Pressure Testing

OPR-99 and CSA Z662-07 require that a pipeline designed for LVP service (such as crude oil service) must first undergo a pressure test before being placed into operation. The pressure test serves two purposes. First, the strength component of a pressure test demonstrates pipeline integrity and that the pipeline is able to withstand the anticipated MOP with a minimum safety margin of 1.25. Second, the leak test ensures that the pipeline is not leaking before it is placed in service. Predominately for safety reasons, pressure tests are conducted using a liquid medium such as water (hydrostatic test). EPI plans to hydrostatically test the LSr Pipeline in accordance with OPR-99 and CSA Z662 requirements.

5.2 Integrity

As an existing EPI pipeline, Line 2 is and would continue to be operated pursuant to EPI's standards and programs, which include the IMP (described in section 3.5.2). Additionally, EPI stated that the new LSr Pipeline would be fully implemented into EPI's integrity management activities and that the Capacity Replacement Project would comply with OPR-99 and CSA Z662-07.

5.2.1 Line 2 Operating Pressures

EPI performed a hydraulic analysis for the entire length of Line 2 in order to increase the pipeline's annual capacity to 70 300 m^3/d by optimizing the design of pump horsepower with DRA injection units. The hydraulic analysis assumed that the maximum discharge pressures downstream of each pumping facility would be limited to current maximum discharge pressures, which are lower than the current MOP of Line 2.

5.2.2 LSr Pipe Thickness and Depth of Cover

MPLA/SAPL expressed safety and integrity concerns regarding the proposed depth of cover of 0.9 m in soil, the class location factor of 1 and the wall thickness of 6.4 mm for the LSr Pipeline. MPLA/SAPL proposed that the LSr pipe be installed at a depth of 1.5 m instead of 0.9 m and that EPI use thicker wall pipe according to Class 3 location requirements.

EPI indicated that safe pipe surface load depends on depth of cover and other factors which include, but are not limited to, pipe wall thickness. EPI agreed that an increase in depth of cover from 0.9 m to 1.5 m would generally enable an increase in surface load allowable over pipe.

EPI submitted that, for pipelines in LVP service such as the LSr Pipeline, CSA Z662 design requirements for depth of cover and wall thickness are not dependent upon class location factors. Accordingly, CSA Z662 specifies a minimum depth of cover of 0.6 m for LVP pipelines regardless of urban or rural areas. EPI noted that the total coverage over the new LSr pipe would typically vary from 1.05 m to 1.1 m by taking into account the topsoil added over construction grade at 0.9 m. Further, the Applicants filed a document entitled *Enbridge Southern Lights Acceptable Agricultural Equipment Crossings (at 0.9 m cover)*, which suggests that farm vehicles and equipment would not be restricted from safely traversing the LSr pipe, and a substantial safety margin would even allow for some pipe depths shallower than 0.9 m.

Monitoring and Mitigation Measures

EPI explained that in addition to meeting CSA Z662 requirements, its pipelines are incorporated into a periodic monitoring program which includes depth of cover surveys and ongoing integrity digs. EPI's existing IMP and specific corrosion management practices include the use of high-performance coatings, a cathodic protection system and periodic ILI and repairs. As well, EPI listed measures to minimize unauthorized contacts with pipe which have been successful in preventing third party damage failures over the past ten years along Line 2, Line 13 and the proposed LSr route.

EPI described its mitigation measures when depth of cover becomes shallower than 0.6 m as follows:

- additional signage and management where public safety is not compromised and where warranted by land use, generally for a short term period;
- mechanical protection in shallow areas such as ditches;
- additional cover in areas that are not subject to erosion; and
- lowering the pipeline in agricultural areas that are subject to erosion.

On 19 October 2007, MPLA/SAPL advised that they had resolved their issues related to the application after reaching a settlement with EPI. The Settlement Agreement lists several commitments made amongst parties to address matters such as depth of cover surveying, coverage over pipe and agricultural equipment and cultivation activities not permitted without further investigation by EPI.

Views of the Board

The Board finds that the Capacity Replacement Project will comply with OPR-99 and CSA Z662-07 and will follow the IMP implemented by EPI.

The increased crude oil capacity on Line 2 will be achieved without an MOP increase through the effective use of pump upgrades and the addition or recommissioning of DRA injection units. The Board has no integrity-related concerns with the Line 2 Modifications, as the amplitude of operating pressures will not be significantly altered to impact the integrity of Line 2.

It is the Board’s view that the LSr Pipeline will be constructed using proven modern or advanced manufacturing, welding and coating practices that will prevent, minimize or delay the occurrence of integrity-related defects. The Board is of the view that it is appropriate that, prior to being placed into crude oil service, the LSr Pipeline be hydrostatically pressure tested in accordance with CSA Z662-07 to validate EPI’s design and construction practices as well as the pipeline’s initial integrity. The Board finds that the proposed depth of cover and pipe wall thickness are adequate for the intended service and location of the LSr Pipeline. EPI shall ensure ongoing pipeline integrity and public safety through its IMP; compliance with the applicable standards or regulations will be verified by the Board during inspections or audits. In particular, EPI shall apply and improve, as necessary, its third party damage prevention measures and the regular depth of cover monitoring and mitigation practices described throughout the Applicants’ submissions.

5.3 Construction and Operation

5.3.1 Joining Programs

EPI has not completed the development of joining programs for the Capacity Replacement Project. However, the evidence provided by EPI forms a framework for the ongoing development of these programs.

Regarding the LSr Pipeline, EPI indicated that joining programs would be developed in accordance with OPR-99 and CSA Z662 requirements. In the application, EPI made high-level statements regarding pipeline joining. EPI indicated that field girth welding of line pipe for the LSr Pipeline would be by manual shielded metal arc welding (SMAW) or mechanized gas metal arc welding. Tie-in welding for the LSr Pipeline would involve a combination of manual SMAW and semi-automatic flux core arc welding. All field girth welds would be non-destructively inspected using ultrasonic or radiographic inspection methods.

The Line 2 Modifications may require welding on liquid-filled piping. If welding occurs on liquid-filled pipeline or components with a CE greater than 0.50 percent, which is a possibility, EPI would be required to submit the welding specifications and procedures and the results of the procedure qualification tests to the Board for approval pursuant to subsection 38(3) of the OPR-99.

Views of the Board

With respect to the LSr Pipeline, the Board currently considers the use of Grade 550 pipe and some of the associated joining and NDE techniques associated with this grade of pipe as either new, unproven or requiring particular attention. With regard to Line 2, the Board would require a joining program for welding on materials with a CE greater than 0.50 percent, to verify that appropriate welding procedures are employed in order to prevent cold cracking in steels with high CEs. The Board notes that the potential for delayed hydrogen cracking increases proportionally with the CE of the base materials to be joined. This effect may be compounded by the quenching effects of flowing liquids within the pipeline on weld deposits placed on the surface of in-service pipelines.

In light of the condition of Line 2 and the proposed use of Grade 550 pipe for the LSr Pipeline, the Board would require EPI to file joining programs for review to ensure that appropriate welding procedures and NDE techniques and processes will be employed. EPI shall demonstrate, through the development of the joining program documentation, the capability of the NDE processes and of EPI’s technicians to consistently and accurately identify and size flaws anticipated by the welding processes.

5.3.2 Leave to Open for Line 2 Modifications Facilities and LSr Station Facilities

EPI requested that the Board, upon the issuance of a Certificate for the LSr Pipeline, grant an order pursuant to section 58 of the NEB Act exempting the LSr Station Facilities from subsection 30 (1)(b) and section 47 of the NEB Act.

EPI also requested that the Board grant an order pursuant to section 58 of the NEB Act authorizing EPI to construct and operate the Line 2 Modifications facilities and exempt these facilities from the provisions of sections 30 and 47 of the NEB Act. Such an order would relieve EPI from having to obtain a Leave to Open order for the Line 2 Modifications facilities.

Views of the Board

The orders sought in respect of the LSr Station Facilities and Line 2 Modifications would relieve EPI from having to seek Leave to Open orders in respect of these facilities.

EPI will design the LSr Station Facilities and the Line 2 Modifications in accordance with OPR-99 and CSA Z662-07. During construction, Board inspectors will verify EPI's implementation of its designs and the quality control provided. Through its construction oversight, the Board would verify that the foregoing facilities are safe and that construction and commissioning will be monitored to ensure that standards are met.

Therefore, pursuant to section 58 of the Act, the Board would exempt the LSr Station Facilities and Line 2 Modifications from the requirement to seek Leave to Open orders.

5.4 Socio-Economic Matters

The Board requires companies to identify and consider the impacts a project may have on socio-economic conditions including the mitigation of negative impacts and enhancement of project benefits.

5.4.1 Land Use

In its application, EPI stated that most of the land traversed by the LSr Pipeline would be privately owned agricultural lands. The application also indicates that the Town of Morden, Manitoba and a local golf course may be affected by the LSr Pipeline. The issues of depth of cover and potential disruption to the Town of Morden and the golf course are set out below.

Depth of Cover

The application contained concerns raised by landowners about their safety when operating equipment and vehicles over pipelines. These points were also raised by intervenors in these proceedings.

EPI submitted that it will install the proposed pipeline at a depth of 0.9 m, which exceeds the CSA standards. EPI submitted that this depth of cover provides sufficient protection and allows equipment typically used in agricultural activities to safely cross the pipeline.

In its evidence, EPI acknowledged that its integrity dig program has revealed locations along existing pipelines that would be adjacent to the proposed LSr Pipeline where the depth of cover was shallower than 0.6 m. In these cases, EPI submits that mitigation measures, appropriate to the particular location, were applied including: additional signage and management, additional cover, lowering the pipeline and mechanical protection.

The Settlement Agreement between EPI and the MPLA/SAPL, filed on the record of these proceedings, includes a section dealing with depth of cover. The Agreement states that EPI will undertake a depth of cover survey of its existing lines that are within or contiguous with the LSr Pipeline and, where the depth is found to be less than 0.6 m and the reduced depth is a safety concern or causes interference with cultivation, EPI will restore the depth to 0.6, implement other mitigative measures or compensate the landowner for resulting crop loss or damages.

Disruptions to Town of Morden and Golf Course

The application indicated that there may be disruption caused to the Town of Morden and the local golf course during construction.

EPI has confirmed that it will develop urban construction plans for the Town of Morden and the golf course and that those plans will be developed in consultation with those affected. EPI has further committed to including those urban construction plans in its Environmental Protection Plan (EPP).

Views of the Board

The Board notes that EPI indicated that there are approximately 365 private landowners and approximately 277 tenants whose land will be traversed in Manitoba. MPLA represents 178 Manitoba landowners; it is not clear whether all own land along the proposed LSr Pipeline route.

Safety of NEB-regulated facilities is a priority for the Board. The concern about the safety of the proposed LSr Pipeline that was expressed by MPLA members may be satisfactorily addressed by the Settlement Agreement they have negotiated with EPI. However, the Board is mindful that landowners who are not members of MPLA may also have concerns.

In considering these possible outstanding concerns, the Board notes that EPI would construct the LSr Pipeline at a depth of 0.9 m, which exceeds CSA standards. In addition, the Board would require EPI to implement a depth of cover monitoring program. In the Board’s view, safety concerns related to depth of cover would be adequately addressed through the implementation of these measures.

With respect to the disruptions to the Town of Morden, and the local golf course that may be caused by construction of the LSr Pipeline, the Board is of the view that the development of urban construction plans in consultation with those affected will adequately address the issue.

5.4.2 Emergency Services and Local Accommodation

The application indicated that police officials and municipal representatives expressed concerns about the potential strain on local communities that could be caused by an influx of construction workers. The police indicated that the amount of pressure would depend on the behaviour of the workers. Municipal representatives noted that the strain on local accommodations would depend on the planning and timing of construction and the associated accommodation.

EPI committed to dealing with these concerns through the development and implementation of a workforce accommodation plan and a written code of conduct. Both of these documents would be attached to the project EPP that will be submitted to the Board for approval prior to commencement of construction.

Views of the Board

The Board recognizes the strain that an influx of hundreds of construction workers can have on local communities. In this case, the Board finds that the measures planned by EPI would address the concerns raised by local police and municipal representatives. In particular, the development and implementation of a workforce accommodation plan and a code of conduct would address the concerns about worker behaviour and pressure on accommodation. The Board notes EPI’s commitment to attach these two documents to its EPP, which would be submitted to the Board for approval prior to the commencement of construction. The Board would also require that all of EPI’s commitments be posted on the company’s web site and be updated at least quarterly.

The Board expects that EPI would obtain all relevant permits and approvals from municipal, provincial and federal agencies for undertaking construction of the LSr Pipeline.

5.5 Part IV Matters

5.5.1 Tolling Methodology

EPI requested approval, under Part IV of the NEB Act, of the tolling methodology to apply to the Line 2 Modifications and the LSr Pipeline prior to the of Line 13. The Capacity Replacement Project is expected to provide additional Mainline capacity by the end of 2008, which is earlier than the closing date for the transfer of Line 13. The closing date is projected to be 31 December 2009 but no later than 1 July 2010. The period between in-service date for the Capacity

Replacement Project and the closing date for the Line 13 Transfer is known as the 'Interim Period'.

EPI proposed that because its Mainline shippers will have access to both Line 13 and the replacement capacity during the Interim Period, the capital and operating costs associated with the Capacity Replacement Project will be borne by its Mainline shippers during that time. EPI undertook to file an application pursuant to Part IV of the NEB Act to recover these costs during the Interim Period, prior to the facilities going into service. CAPP supported this position.

EPI stated that the proposed transfer price of Line 13 ensures that there is no net change to the Canadian Mainline rate base and capital structure. EPI further stated that there would be efficiency gains for the Mainline shippers through the transfer of Line 13 and EPI's role in the ongoing operations of the diluent line and through the incremental revenue from the alternative use of Line 2 breakout tankage at Cromer.

Views of the Board

The Board notes that the proposed tolling methodology was not opposed by any party. CAPP has agreed to EPI's proposal that the capital and operating costs associated with the Capacity Replacement Project will be borne by the Mainline shippers during the Interim Period. The Board is of the view that, because EPI's shippers will have access to both Line 13 and the Capacity Replacement facilities during the Interim Period, it is appropriate that these shippers pay for this benefit. Therefore, the Board is of the view that the applied for tolling methodology for the Line 2 Modifications and the LSr Pipeline project prior to the Line 13 Transfer would result in just and reasonable tolls.

Prior to the facilities going into service, the Board would require EPI to file an application pursuant to Part IV of the NEB Act to recover these costs during the Interim Period.

Chapter 6

Conclusions

6.1 Benefits and Burdens of the Southern Lights Project

The Project involves a number of interrelated applications, including facilities applications made pursuant to Part III of the Act, applications related to tolls under Part IV of the NEB Act and a transfer application pursuant to section 74 of the NEB Act. None of these applications stand alone, they are all required for the Project. Therefore, while the Board has considered the individual requirements for each application it has also considered whether the Project would be in the public interest.

The factors to be considered and the criteria to be applied in coming to a decision on the public interest, or the present and future public convenience and necessity, may vary as a result of many things, including the application, the location, the commodity/ies involved, the various segments of the public affected by the decision, societal values at the time, and the purpose of the applicable section(s) of the NEB Act. The Board must, after carefully weighing all of the evidence in the proceedings, exercise its discretion in balancing the interests of a diverse public.

Overall the Southern Lights Project generates a broad array of benefits and burdens.

Benefits

In terms of benefits, the Board finds that the Project is a cost-effective solution for diluent transportation through an innovative combination of existing infrastructure and new build. The forecasted growth in heavy oil sand bitumen significantly exceeds the currently available condensate supply required to dilute raw production. Negotiations with potential shippers and an open season resulted in the Applicants obtaining sufficient commitments to backstop the capital and operating costs of the Project under long-term contracts. The Project will provide oil sands producers with access to an abundant and low cost diluent supply, which the Applicants maintained is required in order to realize the value of oil sands deposits for the benefit of industry and, ultimately, consumers. According to the Applicants, the Project is also expected to provide a market outlet for refiners recovering incremental quantities of light hydrocarbons in bitumen blends. Therefore, the Project has the potential to provide an efficient recycle solution.

The direct and indirect benefits of the construction phase of the Project are estimated to be Cdn$332.3 million (in 2006 dollars), with the vast majority of the capital outlay (95 percent or $247.5 million) expected to be spent in Canada. The economic effects are expected to be an increase of $133 million in gross domestic product and employment of 1 794 person years. During the construction phase, a total of $33.9 million in taxes would accrue to federal, provincial and municipal governments.

Those shippers that have entered into long-term TSAs receive benefits in the form of competitive negotiated tolls, price certainty and unapportioned access to the pipeline capacity. The Project also benefits those shippers that are not prepared to enter into long-term agreements. The Applicants have stated that sufficient capacity will be retained to provide uncommitted shippers with opportunities to transport diluent to Edmonton.

Although the Project involves the removal of Line 13 from crude oil service, it is expected that EPI's Mainline shippers will benefit from the Project in a number of ways given the planned Line 2 Modifications and LSr Pipeline. As a result of the Project, there will be a 7 500 m^3/day (47 000 bbl/d) expansion of the annual capacity of the Mainline light crude system as measured ex-Cromer as well as increased annual capacity for increasing receipt volumes at Cromer. A short-term Mainline annual capacity increase of 34 800 m^3/day (219 000 bbl/d) will occur as a result of the operation of Line 2 and the LSr Pipeline prior to the reversal of Line 13. Furthermore, there will be improved quality due to segregation of Cromer light sour crude volumes from Line 2 and elimination of Line 2 breakout at Cromer. It is also expected that there will be decreased transit time due to higher pipe velocities and the elimination of Cromer breakout. There will also be additional volumes on the Mainline due to additional diluent supply enabling Canadian heavy crude barrels to be transported. Another identified benefit for the Mainline shippers is an expected improvement in operating efficiencies with ESL sharing operating costs, resulting in an anticipated Mainline toll reduction of approximately $0.02/bbl for all shippers.

Burdens

Most of the burdens associated with the Project are local in scope as is often the case for linear fixed facilities. A number of burdens were identified in the ESR (see Appendix V) to these Reasons. Many of these burdens can be mitigated and the Board assessed and weighed the likely success of potential mitigative options in reaching its determination, under the CEA Act, that the Project is not likely to have significant adverse environmental effects. Nevertheless, some impacts or burdens remain, and they have been considered in the Board's determination under Part III of the NEB Act.

Burdens associated with the Project include direct disruption to land and the activities on that land. The Board recognizes that such disruption could cause a temporary loss of landowners' use and enjoyment of their properties, particularly for those who own or occupy the properties to be crossed by the pipeline RoW. However, the Board finds that, by using existing infrastructure, installing facilities on existing EPI sites and routing the LSR Pipeline to the extent possible along existing RoWs, those disruptions will be minimized. The Board also finds that commitments made by the Applicants to cooperatively work with affected landowners by, for example, establishing Joint Committees and carefully tracking landowner complaints, will further minimize any negative impacts of pipeline construction and operation.

Without appropriate mitigation measures, there is the potential that construction of the LSr Pipeline could disrupt the Town of Morden, and the local golf course, impact the availability of local accommodation and affect agricultural operations. The Board finds that the mitigation measures proposed by the Applicants will minimize the potential for such adverse effects. With respect to disruptions to the Town of Morden and the local golf course that may be caused by construction of the LSr Pipeline, the Board is of the view that the development of urban construction plans in consultation with those affected will adequately address the issue. The

Board also finds that the measures planned by EPI will address the concerns raised by local police and municipal representatives. In particular, the development and implementation of a workforce accommodation plan and a code of conduct will address the concerns about worker behaviour and pressure on accommodation.

The Board is also aware of potential concerns regarding pipeline safety. Safety of NEB-regulated facilities is a priority for the Board. The Board notes that EPI will construct the LSr Pipeline at a depth of 0.9 m, which exceeds CSA standards. In addition, the Board will require EPI to implement a depth of cover monitoring program for the LSr Pipeline. Furthermore, with respect to Line 13, the Board will require ESL to submit an EA at least nine months prior to the reversal of Line 13 in order to confirm ongoing pipeline integrity. Should the Board determine that the EA does not adequately address its concerns, ESL would be required to hydrotest portions of Line 13. In addition, the Board will also require ESL to conduct an emergency response exercise where Line 13 crosses the South Saskatchewan River, and the Board intends to meet with ESL to discuss ESL's emergency response program as it relates to the South Saskatchewan River crossing when the pipeline is operational. With the implementation of these measures, the Board is of the view that any outstanding safety issues of this proposed facility would be addressed.

Several parties raised the possibility of a potential burden on Aboriginal people and their corresponding interests. The Board is of the view that ongoing discussions between the Applicants and Aboriginal groups, coupled with a Heritage Resource Discovery Contingency Plan, will minimize potential impacts on traditional use sites, if encountered. Furthermore, the proposed Project would involve a relatively brief construction phase, with the vast majority of the facilities being buried. As almost all the lands required for the Project have previously been disturbed, are generally privately owned, are used primarily for agricultural purposes and are adjacent to an existing pipeline RoW, the Board is of the view that potential Project impacts on Aboriginal interests will be appropriately mitigated. The Board is therefore of the view that impacts on Aboriginal interests are likely to be minimal.

Balancing of Benefits and Burdens

Having weighed the totality of benefits against the totality of burdens, the Board has determined that the benefits outweigh the burdens and that the Project is in the public interest.

Chapter 7

Disposition

The foregoing constitutes the Board's Reasons for Decision in respect of the applications considered in the OH-3-2007 proceeding.

With respect to the Diluent Pipeline Project, the Board grants EPI leave pursuant to subsection 74(1)(a) of the NEB Act to sell Line 13 in accordance with the terms and conditions set out in the Transfer Agreement. Correspondingly, the Board also grants ESL leave pursuant to subsection 74(1)(b) of the NEB Act to purchase Line 13 in accordance with the terms and conditions set out in the Transfer Agreement. The Board approves the proposed methodology to determine the transfer price and, by virtue of subsection 129(1.1) of the NEB Act, exempts the Applicants from subsection 15(4) of the OPUAR. The Board further approves the reduction of the EPI Mainline system rate base by the Transfer Price, such that the net book values of the LSr Pipeline and Line 2 Modifications are effectively offset in the Mainline system rate base as of the closing date, rather than transferring the amount of the gain or loss from Account 31 (Accumulated Depreciation – Transportation Plant) or Account 32 (Accumulated Amortization – Transportation Plant) to Account 402 (Extraordinary Income) or to Account 422 (Extraordinary Income Deductions) as applicable and as prescribed by section 40(2) of the OPUAR.

The Board grants ESL an order pursuant to section 58 of the NEB Act that has the effect of authorizing the construction and operation of the Line 13 Reversal facilities and exempting these facilities from the provisions of sections 30, 21 and 47 of the NEB Act.

The Board expects the Applicants to apply in due course for any necessary amendments to the pre-existing certificates governing the operation of Line 13 arising from the Line 13 Reversal and Line 13 Transfer.

With respect to the Capacity Replacement Project, the Board approves EPI's application pursuant to section 52 of the NEB Act and will recommend to the Governor in Council that a Certificate be issued, subject to certain conditions (see Appendix III). Further, the Board would grant EPI an order pursuant to section 58 of the NEB Act exempting the LSr Station Facilities from the provisions of subsections 30(1)(b), 31(c), 31(d) and section 47 of the NEB Act concurrently with the issuance of the Certificate for the LSr Pipeline. Further, the Board grants EPI an order pursuant to section 58 of the NEB Act which in effect authorizes EPI to construct and operate the Line 2 Modifications facilities and exempts those facilities from the provisions of sections 30, 31 and 47 of the NEB Act. Finally, the Board approves the tolling methodology to apply to the Line 2 Modifications and the LSr Pipeline prior to the transfer of Line 13 from EPI to ESL.

Given the interrelated nature of the applications, the attached orders will not come into force for the purposes of commencing the construction of any of the applied-for facilities until a Certificate has been issued for the LSr Pipeline. Similarly, leave to transfer Line 13 is subject to the issuance of the applied-for Certificate.

S. Crowfoot
Presiding Member

S. Leggett
Member

K. Batemen
Member

Calgary, Alberta
February 2008

Appendix I

List of Issues - OH-3-2007

The Board has identified but does not limit itself to the following issues for discussion in the proceeding:

1. The need for the proposed projects.

2. The economic feasibility of the proposed projects.

3. The appropriateness of the proposed tolling methodology, the method of toll and tariff regulation and the price at which the Line 13 facilities should be transferred

4. The potential commercial impacts of the proposed projects.

5. The reasonableness of the open season process and the appropriateness of contracted capacity for transportation on the diluent pipeline.

6. The appropriateness of the general route of the LSr Pipeline.

7. The suitability of the design, construction and operation of the proposed new, modified and converted facilities.

8. The potential environmental and socio-economic effects of the proposed new, modified and converted facilities, including those factors outlined in subsection 16(1)[1] of the CEAA:

9. The terms and conditions to be included in any approval the Board may issue.

10. Impacts of the Project on Aboriginal People.

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[1] **16.** (1) Every screening or comprehensive study of a project and every mediation or assessment by a review panel shall include a consideration of the following factors:

(a) the environmental effects of the project, including the environmental effects of malfunctions or accidents that may occur in connection with the project and any cumulative environmental effects that are likely to result from the project in combination with other projects or activities that have been or will be carried out;

(b) the significance of the effects referred to in paragraph (a);

(c) comments from the public that are received in accordance with this Act and the regulations;

(d) measures that are technically and economically feasible and that would mitigate any significant adverse environmental effects of the project; and

(e) any other matter relevant to the screening, comprehensive study, mediation or assessment by a review panel, such as the need for the project and alternatives to the project, that the responsible authority or, except in the case of a screening, the Minister after consulting with the responsible authority, may require to be considered.

Appendix II

NEB Rulings on Motions and Directions

Manitoba Pipeline Landowners Association (MPLA) and Saskatchewan Association of Pipeline Landowners (SAPL) 6 July 2007 Notice of Motion
Ruling Number 1dataed 27 July 2007

Manitoba Pipeline Landowners Association (MPLA) and Saskatchewan Association of Pipeline Landowners (SAPL) 12 July 2007 Notice of Motion #2
Ruling Number 2 dated 9 August 2007

Direction Regarding Standing Buffalo Dakota First Nation (SBDFN) Notice of Motion dated 26 October 2007

National Energy Board | Office national de l'énergie

To: All Parties to OH-3-2007

Hearing Order OH-3-2007
Southern Lights Pipeline Project
Manitoba Pipeline Landowners Association (MPLA) and Saskatchewan Association of Pipeline Landowners (SAPL) 6 July 2007 Notice of Motion
Ruling Number 1

Background

The National Energy Board received a number of related applications for the Southern Lights Project dated 9 March 2007 from Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP (ESL) and Enbridge Pipelines Inc. (EPI) (collectively, the Applicants). The Southern Lights Project consists of a Diluent Pipeline Project, which involves the transfer of the Canadian portion of Line 13 from EPI to ESL and the removal of Line 13 from southbound crude oil service and the reversal of Line 13 to transport diluent from the Canada/U.S. border near Gretna, Manitoba to Edmonton. The proposed Capacity Replacement Project involves the construction of a 286 km light sour crude oil pipeline (LSr Pipeline) from Cromer, Manitoba to the Canada/U.S. border near Gretna and several Line 2 modifications and is intended to offset the reduction of southbound crude oil capacity on the EPI system resulting from the transfer of Line 13 to northbound diluent service.

On 17 April 2007, the Board issued Hearing Order OH-3-2007 in relation to the Southern Lights Project. The Hearing Order outlined the schedule for the Southern Lights proceeding, which included the commencement of the oral Hearing on 13 August 2007. Since the issuance of the Hearing Order, in accordance with the schedule outlined in the Hearing Order, the Applicants have filed additional evidence and responded to a number of information requests. As well, a number of intervenors have filed evidence and information requests have been issued in relation to that evidence.

On 30 May 2007, EPI applied to the Board to construct the Alberta Clipper Expansion Project, a new oil pipeline from Hardisty, Alberta to the Canada/U.S. border near Gretna, Manitoba, and to charge tolls in accordance with a proposed tolling methodology.

On 28 June 2007, the Board issued Hearing Order OH-4-2007 in relation to the Alberta Clipper Expansion Project and decided to convene an oral public hearing beginning 5 November 2007. Applications to intervene in the proceeding are due 30 July 2007.

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MPLA/SAPL 6 July 2007 Motion

The MPLA/SAPL are intervenors in the OH-3-2007 proceeding. On 6 July 2007, the MPLA/SAPL filed a Motion for orders:

(a) Adjourning the hearing of the applications by Enbridge Southern Lights GP Inc. (on behalf of Enbridge Pipelines Inc.) respecting the Line 13 Transfer, Line 13 Reversal and the Capacity Replacement Project, and consolidating said hearing with the hearing of the application by Enbridge Pipelines Inc. for the Alberta Clipper Expansion Project to commence 5 November 2007;

(b) In the alternative, adjourning the commencement of the hearing of the Southern Lights Project application to 5 November 2007, said hearing to be held at the same time and in the same location as the hearing of the Alberta Clipper Expansion Project Application; or,

(c) In the further alternative, adjourning the commencement of the hearing of the Southern Lights Project application to a date no earlier than 29 October 2007.

The MPLA/SAPL stated that the Motion to consolidate the proceedings was supported by the interrelationship between the Southern Lights and Alberta Clipper Expansion Projects. In this regard, the MPLA/SAPL noted that the Southern Lights LSr Pipeline and the Alberta Clipper Pipeline would be constructed in the same easement at roughly the same time which will require additional workspace. The MPLA/SAPL also stated that a joint public consultation program was carried out for both Projects in part for the convenience of the landowners, that Enbridge proposes a form of easement agreement that provides for the installation of "one or more pipelines", and that reclamation is to be delayed until after the installation of the second pipeline. The MPLA/SAPL also referenced the fact that it was of the view that the cumulative effects assessments related to the two Projects is deficient.

The MPLA/SAPL stated that, in light of the interrelationship between the proposed Southern Lights LSr and Alberta Clipper pipelines and the MPLA/SAPL's concern with respect to mitigation strategies to deal with the cumulative impacts of the two Projects, it is vitally important that MPLA/SAPL be able to participate in both proceedings. The MPLA/SAPL noted the expense and time associated with participating in the established regulatory processes and stated that the landowners would face undue hardship if they must participate at their own expense and on their own time in two separate oral hearings before the Board. The MPLA/SAPL stated that Manitoba landowner members of the MPLA face the prospect of the two new Enbridge pipelines going through their farms while the landowner members of the SAPL are concerned that the determination of issues important to agricultural landowners in the Southern Lights Hearing will pre-determine the issues to be addressed in the Alberta Clipper Hearing.

The MPLA/SAPL stated that there are cogent and compelling reasons to consolidate the hearings and that proceeding by separate oral hearings would result in a serious waste of time and resources by all parties, with there being a significant amount of duplication of work. The MPLA/SAPL claimed that the Board could not properly adjudicate on the Southern Lights Application without fettering itself with regard to the other Application and that a "comprehensive approach" to the applications would be more advantageous than a staged one.

The MPLA/SAPL also stated that the current start date of the Southern Lights oral Hearing is likely to coincide with the fall harvest in Manitoba and Saskatchewan and, therefore, the MPLA/SAPL would not have an opportunity to participate in the process without great personal sacrifice.

The Board received a number of submissions with respect to the Motion. The Board notes that the Alberta Federation of Labour filed submissions with respect to the Motion a number of days after the deadline for its submissions, after the parties opposed to the Alberta Federation of Labour's position had submitted their comments. Given that the Alberta Federation of Labour provided no explanation as to why its submission was late and the prejudice that other parties would face as a result of not having an opportunity to reply to the Alberta Federation of Labour's comments, the Board did not consider the Alberta Federation of Labour's when making its determination on the Motion.

Parties in Favour of the Motion

No other parties submitted comments in support of the MPLA/SAPL's Motion within the deadline for comments established by the Board.

Parties Opposing the Motion

A number of submissions were filed in opposition to the Motion within the deadline for comments established by the Board. Devon Canada Corporation, Suncor Energy Marketing Inc., BP Canada Energy Company Limited, Baytex Energy Ltd., Statoil North America, Inc., and CAPP expressed concern that a delay in the regulatory proceedings would result in a delay in the availability of much needed capacity for heavy oil, which was not in the public interest. CAPP specifically claimed that pushing the Line 2 modifications and the LSr Pipeline into the same timeframe as the Alberta Clipper Expansion Project would push completion from the end of 2008 into 2010 and would add to the risk of cost overruns for both Projects. Baytex Energy Ltd. and Statoil North America, Inc. specifically expressed concern about how a delay could impact the availability of diluent.

CAPP further submitted that the Southern Lights Project and Alberta Clipper Expansion Project are different projects with different applicants. CAPP claimed that the Applicants have packaged all components of that Project into one entirely proper application and the Applicants were entitled to have the application heard in a timely manner. Devon claimed that, once a process for project review has been established, there is an expectation that the timing associated with such a process will be maintained. BP Canada Energy Company Limited similarly argued that the Southern Lights and Alberta Clipper Expansion Projects are different projects with different applicants, parties, routes, products and critical paths.

The Applicants argued that the facts stated in the Motion were selective and incomplete. Additional facts identified by the Applicant included the fact that the Southern Lights Project involved a number of applications, with the Applications respecting the Line 13 transfer and reversal and the Application respecting the Line 2 modifications not involving any new pipeline construction or land acquisition and the LSr Pipeline not involving any new pipeline construction or land acquisition in Alberta or Saskatchewan. The Applicants noted that the schedule for the Project is based upon receiving regulatory approval of the Project Applications by 31 December 2007. The Applicants stated that the Southern Lights Project was developed to respond to industry demand for additional diluent supply in Western Canada while the Alberta Clipper Expansion Project was developed to respond to industry demand to increase the pipeline take away capacity from Western Canada to accommodate expected oil sands production and would be integrated to form part of the existing Enbridge Mainline system. The Applicants also stated the different targeted construction completion dates for the two Projects. The Applicants maintained that what was evident from the additional facts was that the Southern Lights Project and the Alberta Clipper Expansion Project are separate projects, have separate purposes, are subject to different commercial agreements with different parties and have different schedules.

With respect to the claims in the MPLA/SAPL Motion that the Southern Lights Application failed to properly assess and address and/or provide adequate mitigation strategies to deal with cumulative impacts of the proposed Project as well as Enbridge's existing pipelines, the Applicants stated that these allegations would be addressed at the OH-3-2007 Hearing and that the allegations did not provide grounds to adjourn the hearing.

With respect to the request to consolidate the two hearings and the argument that MPLA cannot afford the time and money required to take part in two oral Hearings, the Applicants noted that of those MPLA landowners that had filed evidence, it only anticipated asking questions of one landowner and that the Applicants were prepared to work with the Board and intervenors to ensure that his appearance at the hearing is scheduled to minimize his time and expense. With respect to the SAPL concern that consolidation is required due to a concern that the determination of issues important to agricultural landowners in Southern Lights will pre-determine the issues to be addressed in the Alberta Clipper Expansion Project hearing, the Applicants noted that the Southern Lights Project involved no new pipeline construction or land acquisition in Saskatchewan and the fact that it is trite law that no panel of the Board is bound by the decision of another panel.

The Applicants noted that the Board has acknowledged that there is often some overlap between hearings given the nature of the industry and that the Board would consider hearing separate applications together if proceeding by way of separate applications would result in an abuse of process or a serious waste of time and resources by the Board and all parties. The Applicants acknowledged that the Southern Lights Project and the Alberta Clipper Expansion Project may give rise to some overlap of issues for some landowners in Manitoba; however, the Applicants claimed that proceeding with the scheduled OH-3-2007 Hearing would not result in an abuse of process or a serious waste of time and resources. The Applicants stated that the Board has a legal obligation to hear an application so long as it is complete and is not being brought forward in a piecemeal fashion for inappropriate purposes. The Applicants submitted that the Southern Lights Project Applications are complete and that the Board therefore has a legal obligation to hear them without delay.

The Applicants concluded by noting that the Board must make its decision in the public interest, which includes the interests of all Canadians, including the interests of the MPLA/SAPL, the Applicants, the shippers, and Western Canadian oil producers. According to the Applicants, the Canadian public interest would not be served by delays in the Southern Lights Project approval process and the proposed in-service dates of the Project facilities.

MPLA/SAPL Reply

The MPLA/SAPL submitted that comments regarding the adjournments potentially resulting in the delay of the in-service date of the Southern Lights Project should be disregarded because it assumes that the Board will approve the Project. The MPLA/SAPL noted that no parties had filed evidence demonstrating that an adjournment of the commencement of the Hearing to the dates proposed would prevent a determination by the Board of the Applicants' Applications on or before 31 December 2007. The MPLA/SAPL noted that several of CAPP's assertions, including the risk of cost over runs for both Projects if Southern Lights is pushed into the same timeframe as the Alberta Clipper Expansion Project, were not supported by any evidence and should be disregarded.

The MPLA/SAPL submitted that the Board must consider the point of view of directly affected landowners, who will face the installation of two additional pipelines within five metres of each other within a one to two year period. The MPLA/SAPL stated that an adjournment of the Southern Lights Hearing is critical to addressing landowner concerns about the Applicants' proposals and is critical to fulfilling its objectives of fostering stakeholder participation and the duty to ensure fairness and natural justice.

With respect to the BP Energy comments, the MPLA/SAPL emphasized that BP Canada's interests in the proceeding relate to its ownership of U.S.-based refineries and that the Board should give greater weight to the concerns of directly affected Canadian pipeline landowners as the Board must decide matters according to the Canadian public interest.

MPLA/SAPL noted that it was for the Board to determine its own process and that the MPLA/SAPL had not requested for the Projects to proceed in lock-step fashion.

The MPLA/SAPL further clarified that the transfer of Line 13 from EPI to a different company raises significant landowner concerns and claimed that the fact that no new land will be acquired by the Applicants does not mean that the Line 13 proposal has no impact on landowners.

The MPLA/SAPL stated that the relief sought is necessary, in light of the alleged failures by the Applicants to address cumulative impacts adequately, to help ensure that sufficient information regarding the Alberta Clipper Expansion Project is before the Board on the hearing of the Southern Lights Application.

In terms of landowner participation in the Hearing and the Applicants anticipation that they would only have questions for one of the landowners who filed evidence, the MAPL/SAPL submitted that landowner participation in the hearing is not limited to the attendance at the oral hearing by only one landowner representative. The MAPL/SAPL indicated that their members want to attend the oral hearing to hear firsthand how the Applicants intend to deal with landowner concerns and that they want to be present to hear the evidence of all witnesses, provide information and instructions to counsel and listen to argument. Further, the MAPL/SAPL submitted that the Applicants did not make any suggestion about how the Board might facilitate the participation of the landowners. The MAPL/SAPL offered to work with the Board on the formulation of a consolidated hearing schedule in November 2007 related specifically to issues of concern to landowners and that this would allow the oral hearing on issues not related to lands and landowners to proceed prior to November 2007.

The MPLA/SAPL noted that the SAPL concern about the influence any decision by the Board regarding landowner issues in the Southern Lights hearing may have on a subsequent decision by the Board in the Alberta Clipper Expansion Project proceeding stemmed from the fact that nearly identical Environmental and Socio-Economic Impact Assessments have been filed by the Applicants for both proposed Projects. The MPLA/SAPL concluded that not evaluating in the same or consecutive proceedings the similar deficiencies in the Applicants' assessment of the cumulative affects of these Projects to be constructed consecutively in the same easement with common consultation, construction methodology, reclamation, mitigation and compensation constitutes an abuse of process and a serious waste of time.

Views of the Board

Consolidation of Southern Lights Project and Alberta Clipper Proceedings

The Board is of the view that generally applicants are entitled to frame their application as they determine to be appropriate. The Board has a legal obligation to hear an application so long as it is complete and is not being brought forward in a piecemeal fashion for inappropriate purposes. The Board has acknowledged that, given the nature of this industry, there is often some overlap between hearings. Nevertheless, if the Board were of the view that proceeding by way of separate applications would result in an abuse of the process or a serious waste of time and resources by the Board and all parties, it may require them to be heard together.

It is the Board's understanding that the overlap of issues of concern between the Alberta Clipper Expansion Project and the Southern Lights Pipeline Project relates largely to the Application to construct the LSr Pipeline. The parties have not raised concerns with respect to the potential overlap of issues between the Alberta Clipper Expansion Project and the other Southern Lights

Project applications respecting the Line 13 transfer and reversal and the Line 2 modifications. The Board notes, however, that the stated need for the construction of the LSr Pipeline is linked to the Line 13 transfer and reversal.

In the Board's view, it is not apparent that the Applicants for the Southern Lights and Alberta Clipper Expansion are proceeding by way of separate applications in order to avoid jurisdiction or some process, or as a form of project splitting. No party has alleged that that is the case. Rather, the Board is of the view that there is a legitimate delineation between the applications for the Southern Lights Pipeline Project and the Alberta Clipper Expansion Project. While the Applicants and the Board have taken some steps to consolidate the processes related to the two proceedings, through joint public consultation/presentations, the two Projects have two separate purposes. Although the MPLA/SAPL notes that the Alberta Clipper Pipeline and the Southern Lights LSr will be constructed in the same easement at roughly the same time, the Panel understands that the Projects as a whole have distinct schedules.

With respect to the MPLA/SAPL's suggestion that the cumulative impacts of the Projects and the lack of assessment of those impacts warrant consolidating the proceedings, the Board notes that the cumulative impacts of the Alberta Clipper Expansion Project and the Southern Lights Project must be considered in the context of the Southern Lights Project proceeding. The Applicants have assumed a risk of their applications being denied if the cumulative impacts assessment is deficient. In the Board's view, this is not a ground for consolidating the proceedings.

SAPL's concerns that the Board's determination in the Southern Lights proceeding will pre-determine matters in the Alberta Clipper Expansion proceeding are unwarranted. The Board is required to adjudicate the Southern Lights proceeding without fettering itself with regard to the Alberta Clipper Expansion Applications. Natural justice precludes the Board from fettering its discretion and it is well understood that the determinations of one Board panel do not bind the determinations of another Board panel.

Although the Board acknowledges that some of the issues addressed in the Southern Lights Project proceeding and the Alberta Clipper Expansion Project proceedings may be similar, the Board is of the view that such overlap is not uncommon in Board proceedings. Furthermore, the Board is concerned that a consolidation of the proceedings may result in added expense for parties who are only interested in one of the two Projects.

The Board has determined that it is not an abuse of the process nor a serious waste of time and resources by the Board and all parties for the Southern Lights Project and the Alberta Clipper Expansion Project to be considered in separate proceedings. Therefore, the Board has determined that it will not consolidate the two proceedings.

Adjournment Until After Harvest and Holding Concurrent Proceedings

The Board has determined that it is not practical to hold concurrent proceedings. However, the Board acknowledges the value of the effective participation of landowners in its proceedings. NEB Goal 2 states that NEB regulated facilities are to be built and operated in a manner that respects the rights of those affected. Similarly, Goal 4 states that the NEB fulfills its mandate with the benefit of effective public engagement. The Board expects the effective use of hearing time, which is assisted when interested persons with similar concerns join together and present their positions in a single intervention. The Board notes that the MPLA/SAPL is arguably the most active intervenor in the Southern Lights proceeding, having filed substantial evidence and asked a number of information requests.

The Board is mindful that several parties opposed to the Motion have suggested that a delay in obtaining the necessary regulatory authorization will result in delay in much needed additional capacity offered by the Line 2 modifications and the LSr Pipeline coming on line. The Board notes that the Line 2 modifications and the new LSr Pipeline are intended to replace the loss of capacity associated with the proposed Line 13 reversal, which will not occur until a couple of years after the Line 2 modifications and LSr Pipeline are scheduled to be in service.

The Board wishes to maximize the use of the scheduled hearing time while accounting for the scheduling constraints of the MPLA/SAPL. The MPLA/SAPL expressed their strong desire to increase the effectiveness of the hearing process and to avoid waste of time and resources. The Board is prepared to be responsive to the MPLA/SAPL's request with respect to the conflict between the Southern Lights oral Hearing schedule and harvest; however, the Board is also concerned with the effective use of time and resources. Therefore, the Board expects all parties to work together to ensure an efficient and effective use of hearing time.

After considering the submissions of the parties made in accordance with the Board's schedule for comments on the 6 July 2007 Motion, the Board has determined that it will commence the Southern Lights oral Hearing beginning at **8:30 am, Monday, 13 August 2007 in the Hearing Room of the Board's Offices in Calgary, Alberta**. The Board expects that, with the exception of the MPLA/SAPL and the Standing Buffalo Dakota First Nation, during the proceedings held in Calgary, all intervenors will cross-examine the Applicants' witness panels on all issues of interest to them. Once the cross-examination of the Applicants' witness panels by all intervenors other than the Standing Buffalo Dakota First Nation and the MPLA/SAPL is completed, the Board will hear from the witness panel of the Communication Energy and Paperworkers Union of Canada (CEP).

Once the examination of the CEP witness panel is completed, the Board will adjourn the proceeding. The Board will recommence the oral Hearing at **8:30 am Monday, 20 August 2007 in Regina, Saskatchewan in the Novara Ballroom at the Saskatchewan Trade & Convention Centre (Delta Regina Hotel)**. The Standing Buffalo Dakota First Nation will then have an opportunity to cross-examine the Applicants' witness panels. The Board will then hear from the Standing Buffalo Dakota First Nation witness panel.

Following the cross-examination of the Standing Buffalo Dakota First Nation witness panel in Regina, the Board will adjourn its proceedings. The Hearing will recommence at **8:30 am Monday, 29 October 2007 in Brandon, Manitoba at a hearing location to be determined**. Upon recommencing the proceedings, the MPLA/SAPL will cross-examine the Applicants' witness panels and the MPLA/SAPL will seat their witnesses. Upon conclusion of the cross-examination of the MPLA/SAPL witnesses, the Board will hear any rebuttal panels and oral argument. Parties may submit written argument provided it is received by all parties in advance of the commencement of oral argument.

The Board requires the best efforts of all parties to enable an efficient and effective hearing process. In this respect, the Board directs the Standing Buffalo Dakota First Nation and the MPLA/SAPL to identify the issues that they expect to be cross-examining on so that the Applicants will be able to ensure that the appropriate witnesses are made available for cross-examination in Regina, Saskatchewan and Brandon, Manitoba. The Board asks that the Standing Buffalo Dakota First Nation and the MPLA/SAPL file this information by no later than 10 August 2007.

The Board notes that it is open to parties to canvas other parties to determine whether their panels will be cross-examined; if no cross-examination is to occur, parties may adopt their evidence by way of Affidavit.

All other procedural steps should accord with the timeline outlined in Hearing Order OH-3-2007.

Yours truly,

for

David Young
Acting Secretary

National Energy Board
Office national de l'énergie

File OF-Fac-Oil-E242-2007-01 01
9 August 2007

To: All parties Hearing Order OH-3-2007

Hearing Order OH-3-2007
Southern Lights Pipeline Project
Manitoba Pipeline Landowners Association (MPLA) and Saskatchewan Association of Pipeline Landowners (SAPL) 12 July 2007 Notice of Motion #2
Ruling Number 2

MPLA/SAPL 12 July 2007 Motion

On 12 July 2007, the MPLA/SAPL, intervenors in the OH-3-2007 proceeding, filed a Motion for orders:

(a) Directing the Applicants, Enbridge Southern Lights GP, Enbridge Southern Lights LP (ESL) and Enbridge Pipelines Inc. (EPI) (collectively, the "Applicants") to provide full and adequate responses on or before 30 July 30 to various Information Requests submitted by MPLA and SAPL to the Applicants;

(b) Directing the Applicants to produce to MPLA and SAPL on or before 30 July 2007 or, where they have not yet been prepared, forthwith following their completion, the documents requested in various Information Requests submitted by MPLA and SAPL to the Applicants; and,

(c) Staying the herein proceedings until such time as the Applicants provide the information requested in subparagraphs (a) and (b) above.

On 16 July 2007, the Board issued a letter outlining a process for submitting comments on the Motion. The Applicants filed their comments in opposition to all aspects of the Motion on 20 July 2007. Statoil North America, Inc. and the Canadian Association of Petroleum Producers each filed a submission expressing their opposition to the requested stay. Other than MPLA/SAPL, no parties made submissions in favour of the stay. MPLA/SAPL filed its reply submission on 23 July 2007. The complete text of all comments and submissions can be found on the Board's website under the Southern Lights folder.

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Criteria for Responding to Information Requests

The Board has outlined the criteria for responding to Information Requests in a number of its previous rulings.[1] With respect to the general purpose of information requests and the criteria used to decide when an applicant will be directed to respond to a request, the Board has previously stated:

> The Board process allows for the use of written information requests for a number of reasons. Applications before the Board require the consideration of substantial information, much of it of a detailed and technical nature. Often this information is not conducive to an examination by the oral cross-examination process. Parties are therefore encouraged to obtain and examine such information through the established information request process. This process can be used to obtain the evidence necessary to test and explore the Applicant's case and, in the case of Intervenors, to assist them in preparing their cases.
>
> …When the parties cannot agree on the appropriateness of the Information Request or the adequacy of a Response, the Board is asked to provide direction.
>
> When considering such a motion, the Board looks at the relevance of the information sought, its significance and the reasonableness of the request. It seeks to balance these factors to ensure that the purposes of the Information Request process are satisfied, while ensuring that an Intervenor does not engage in a "fishing expedition" that could unfairly burden the Applicant.[2]

The criteria of relevance, significance and reasonableness have been applied in a number of proceedings before the Board.[3] In determining whether the information sought to be elicited through the information request process in this proceeding should be provided, the Board is of the view that a similar analysis should be undertaken. The Board will evaluate whether the request is relevant, reasonable and significant and balance these factors to ensure that the above-stated purpose of the information process has been satisfied while ensuring that the Applicants are not unduly burdened by questions that are more in the nature of a "fishing expedition".

After considering the submissions of the parties, the Board has determined the following on each of the various Information Requests (IR).

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[1] Chevron Canada Limited, Chevron Standard Limited and Neste Canada Inc. Application for Priority Destination (MH-2-2005), Board Decision on Motion filed by Tesoro Canada Supply & Distribution Ltd., Ruling Number 2; Emera Brunswick Pipeline Company Ltd. Application for the Brunswick Pipeline (GH-1-2006), Board Decision on Ms. T. Debly's Notice of Motion to require EBPC to respond to Information Requests, Ruling Number 7

[2] Westcoast Energy Inc. (GH-5-94), Transcript Volume 3 (8 February 1995), at 340-342.

[3] For example, the Board's Letter Decision dated 5 September 2002 on Westcoast Energy Inc.'s Southern Mainline Expansion Project (GH-1-2002) and the Board's Letter Decision dated 14 February 2003 on Sumas Energy 2, Inc.'s application for an international power line (EH-1-2000).

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<u>Information Requests 1.5 (f), 1.17, 1.21(a), 1.21 (c), 1.48(f), 1.50(b) and 1.51,</u>

The MPLA/SAPL have indicated that they were satisfied with the Applicants' responses to Information Requests 1.5(f), 1,17, 1.21(a), 1.21(c), 1.48(f), and 1.51. With respect to IR 1.50(b), the MPLA/SAPL acknowledged that, subject to the timely receipt of the Applicants' summary and the MPLA/SAPL's review of that information, the Applicants' proposed response would be adequate. Therefore, the Board need not rule with respect to these Information Requests.

<u>Information Requests 1.2 (d) and 1.2 (e)</u>

IR 1.2(d) and 1.2(e) refer to the identification of locations where the proposed routing for the LSr pipeline comes within various distances of residences and farmyards, respectively. The Applicants have supplied the locations for residences and farmyards within 30 metres of the proposed LSR pipeline right-of-way and have indicated that a survey has yet to be done to determine the precise distances of separation. The MPLA/SAPL have indicated that, if the requested information is presently available, they maintain their request for a full and adequate response.

The Board understands the Applicants' response as indicating that the requested information is not presently available as a survey has not been performed. In any event, the Board is of the view that the information requested would not be of sufficient significance or probative value at this stage of the Board's evaluation of the LSr pipeline proposal to require the Applicants to undertake a further response. Such detailed information is more appropriately the subject of discussion during detailed route proceedings. The Board, therefore, dismisses the MPLA/SAPL's motion with respect to these Information Requests.

<u>Information Requests IR 1.6(b), 1.21(d), 1.64(d) and 1.64(e)</u>

In IR 1.6(b), the MPLA/SAPL requested details for the calculations underlying the Applicants' estimated capital cost for land acquisition. In response to the MPLA/SAPL Motion, the Applicants noted their original response to the IR that the estimated capital cost of land is comprised of the cost of services and administration associated with the land acquisition, plus the cost of acquiring the land and settling the losses and damages arising from construction. EPI advised that these costs were estimated to be $2.5 million and $9.5 million, respectively. The MPLA/SAPL stated that, in order to evaluate the adequacy of the Applicants' proposed mitigation of construction damages through compensation, they require a breakdown of the $9.5 million cost for acquiring the land and settling the losses and damages arising from construction as between land acquisition costs and construction damage and loss related costs.

IR 1.21(d) requests Enbridge's policy for crop loss compensation. Initially the Applicants refused to answer this Information Request on the basis that the issue of compensation is beyond the jurisdiction of the Board; however, in response to the Motion, the Applicants replied that landowners would be compensated for all crop losses and the Applicants would handle those on a case-by-case basis. MPLA/SAPL submitted that they require further details from the Applicants regarding the determination of crop loss compensation, including the measurement of yield loss, the determination of applicable crop prices and the timing of payment of landowners.

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In IR 1.64(d), the MPLA/SAPL requested any crop loss studies conducted by or for Enbridge related to its past or present construction practices. While initially the Applicants refused to answer this Information Request on the basis that the issue of compensation is beyond the jurisdiction of the Board, in response to the Motion, the Applicants responded that no crop loss studies have been prepared by or for Enbridge related to its past or present construction practices.

With respect to IR 1.64(e), MPLA/SAPL stated that they require details of past crop loss claims made to the Applicants and the resolution of those claims in order to assess the adequacy of the mitigation strategy. The Applicants initially refused to answer this Information Request on the basis that the issue of compensation is beyond the jurisdiction of the Board. In response to the Motion, the Applicants indicated that details of past crop loss claims made by landowners are not germane to the consideration of the LSr pipeline application and expressed concern about publicly disclosing such particulars.

The Board accepts that the Applicants have proposed compensation as one of the mitigation measures to address various Project impacts and that for that limited purpose compensation is relevant. Although, the Board recognizes that the sufficiency of compensation as a mitigation measure is relevant. Although the Board has no authority within the *National Energy Board Act* to establish the appropriate level of compensation, the *National Energy Board Act* establishes a separate process administered by the Minister of Natural Resources Canada to address situations where a company and an owner of lands have not agreed on the amount of compensation payable under the Act for the acquisition of lands or for damages suffered as a result of the operations of the company or on any issue related to that compensation. This process ensures that there is an avenue available to both companies and landowners to ensure that compensation matters can be determined in accordance with legislated guidelines such as those outlined in Section 97 of the Act. Section 97 states that an Arbitration Committee must determine all compensation matters referred to in a notice of arbitration served on it and in doing so shall consider, where applicable, the loss of use to the owner of the lands by the company. The existence of this process means that the details and appropriateness of compensation proposals can be evaluated in the context of such proceedings.

The Board is satisfied that the Applicants have responded fully to both IR 1.21 and IR 1.64(d). With respect to the detailed information requested in IR 1.6(b) and IR 1.64(e), the Board is of the view that, balancing the three criteria of relevance, significance and reasonableness, these Information Requests seek information that does not appear to be sufficiently significant or probative to the Board's assessment to require the Applicants to undertake a further response to these Information Requests. Therefore, the Board declines to order the Applicants to file further responses to IRs 1.6(b), 1.21, 1.64(d) and 1.64(e).

IR 1.32 and 1.34

The MPLA/SAPL requested copies of EPI's existing operations and maintenance manuals as well as EPI's Engineering Standards and Guidelines. The MPLA/SAPL submitted that this information was necessary in order to fully and adequately assess the Applicants' assurances that

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safety and stewardship of the natural environment are addressed by Enbridge's operational policies, practices and activities.

The Applicants indicated that the referenced operations and maintenance manuals only relate to existing pipelines and have yet to be revised to incorporate the proposed facilities. With respect to the Applicants' Engineering Standards and Guidelines, the Applicants have commented that these Standards and Guidelines contain commercially valuable information and are proprietary to EPI. The Applicants further stated that the Applicants will comply with the requirements of the *Onshore Pipeline Regulations, 1999* and with the standards of the Canadian Standards Association Z662-03. The Applicants have indicated that they have provided significant information respecting their plans for the construction and operation of the LSr pipeline and that they have described the contents of the detailed manuals and programs that will be developed. The Applicants have also stated that they would answer hearing questions regarding their plans for the construction and operation of the LSr pipeline, including questions with respect to how the LSr pipeline will be constructed and operated in a manner that ensures safety and protects the environment.

The Board notes that the operations and maintenance manuals requested do not currently relate to the proposed Southern Lights Project and that these manuals will be revised to incorporate the Line 13 reversal, the Line 2 modifications and the LSr pipeline. Given that these manuals do not currently address the proposed Project, the Board declines to order the Applicants to provide copies of its existing operations and maintenance manuals as requested in IR 1.32.

With respect to the request for the Applicants' Engineering Standards and Guidelines, the Board notes the significant number of documents listed in Table A-2 of the Application. The NEB Filing Manual requires confirmation that the applied-for project will comply with company manuals and confirmation that these manuals comply with the *Onshore Pipeline Regulations, 1999* and the codes and standards for the Project. The Applicants have indicated in their Application that the Project will comply with company manuals and that these manuals comply with *Onshore Pipeline Regulations, 1999* and codes and standards. The Board notes that parties will have the opportunity to question the Applicants with respect to their proposed construction and operation practices.

The Board will not refuse access to potentially relevant information on the basis that all precautions taken to protect the confidentiality of the information may fail, when there is no evidence before the Board that this is a realistic possibility. However, with respect to the MPLA/SAPL's request for copies of all of the referenced Engineering Standards and Guidelines, the Board is of the view that, on balance, the detailed information requested by MPLA/SAPL is not sufficiently significant or probative to the Board's assessment to require the Applicants to respond to the these Information Requests. The Board therefore declines to order the requested relief with respect to IR 1.34.

IR 1.37, 1.40, 1.41, 1.43 and 1.78

The MPLA/SAPL initially requested that the Board make an order requiring the Applicants to produce a copy of the following documents related to the LSr pipeline: construction plan;

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construction contracts; documented inspection plans; operations plan; and an environmental handbook. After the Applicants indicated that these documents would not be available until the close of the evidentiary record in the OH-3-2007 proceeding, the MPLA/SAPL requested that any existing draft or precedent versions of these documents be made available.

The documents requested by MPLA/SAPL do not currently exist and will likely not exist until the close of the evidentiary record. The Board notes that the *Onshore Pipeline Regulations, 1999* include specific requirements with respect to filing certain manuals and that the Board can propose conditions to be included in a Certificate, requiring certain documents to be filed with the Board.

The Applicants bear the burden of providing sufficient information in support of their Applications. The Applicants have indicated that they have provided significant information respecting their plans for the construction and operation of the LSr pipeline and that they have described the contents of the detailed manuals and programs that will be developed. They have also committed to answering hearing questions regarding their plans for the construction and operation of the LSR pipeline, including questions with respect to how the LSr pipeline will be constructed and operated in a manner that ensures safety and protects the environment.

While the MPLA/SAPL have requested that any existing draft or precedent versions of these documents be made available, the Board is of the view that, given that drafts or precedent versions of such documents are subject to change, the filing of draft documents would not assist the Board in its evaluation of the Applications. The Board therefore declines to order the requested relief with respect to IRs 1.37, 1.40, 1.41, 1.43 and 1.78.

IR 1.50(c)

In IR 1.50(c), the MPLA/SAPL requested details of all landowner complaints received by EPI with respect to integrity digs conducted in the past 10 years on the properties of landowners who will be affected by the LSr pipeline construction. The Applicants noted that the requested information is not readily available because EPI does not separately track complaints that relate specifically to integrity digs.

The Board is of the view that the requested information is of limited relevance to the proceeding and it would not be reasonable to require the Applicants to file the requested information. Further, the Board notes that a formal landowner complaints process exists where concerns with respect to existing pipelines can be vetted by the Board.

IR 1.81(c)

In IR 1.81(c), the MPLA/SAPL requested copies of depth of cover surveys conducted in 1991 on existing pipelines. The Applicants noted that the survey results do not contain information about the depth of cover proposed for the LSr pipeline and that the documentation comprises many volumes of survey readings taken at 50 metre intervals along the route of the pipelines. The MPLA/SAPL expressed its understanding that cover over the existing pipelines may be reduced

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over time by erosion of the soil and other factors. The MPLA/SAPL argued that they require information related to the depth of cover of those existing pipelines in order to test the adequacy of the proposed 0.9 metres depth of the LSr pipeline in relation to land use restrictions that may apply to LSr pipeline easement lands. The MPLA/SAPL state that the Applicants should be required, at the very least, to provide depth of cover survey information related to the properties of MPLA/SAPL members.

The Board is of the view that the 1991 depth of cover surveys for the existing pipelines are of limited relevance to the Board's assessment of the LSr pipeline Application. Matters related to existing pipelines can be addressed through the landowner complaints process. More relevant to the Board's determination is information related to how the Applicants proposes to mitigate diminishing depth of cover and the success/failure rates of such mitigation measures in respect of the LSr pipeline. The Board therefore requires EPI to respond to the following:

> Based upon the latest information collected (during depth of cover surveys, integrity digs, etc.) along the existing mainline pipelines adjacent to the proposed route for the LSr pipeline, are there locations where depth of cover has become shallower than the applicable CSA standard for construction? Please describe in detail the mitigation measures applied to areas where depth of cover has become shallower than the applicable CSA standard for construction along the existing mainline pipelines adjacent to the proposed route for the LSr pipeline, including a description of why the particular mitigation measure was selected and an assessment of pros and cons of each mitigation measure.

The Board requests that the Applicant respond to this information request by **noon, Friday 7 September 2007.**

Request for a Stay

Given the Board's determination on parts (a) and (b) of the MPLA/SAPL's motion, the Board is of the view that a stay of the OH-3-2007 proceedings is not necessary and dismisses the MPLA/SAPL's request for a stay.

Yours truly,

David Young
Acting Secretary

National Energy Board
Office national de l'énergie

File OF-Fac-Oil-E242-2007-01 01
26 October 2007

To: All parties Hearing Order OH-3-2007

Hearing Order OH-3-2007 Southern Lights Pipeline Project
Direction Regarding Standing Buffalo Dakota First Nation (SBDFN) Notice of Motion

In accordance with the Board's letter outlining the process for parties to make submissions regarding the SBDFN Notice of Motion dated 10 October 2007, (the Motion) the Board has received submissions from the Applicants and the Canadian Association of Petroleum Producers opposing the Motion. The Board has also received the SBDFN's reply to those submissions.

In addition to providing a reply to the submissions of other parties on the Motion, the SBDFN raises a further issue "in relation to reasonable apprehension of bias". The SBDFN submits that there has been "a breach of the rules of natural justice and the Board's duty of procedural fairness" and asks this Board to "recuse itself and declare this proceeding a nullity."

Although these allegations have not been properly brought before the Board in the form of a Notice of Motion as required pursuant to section 35 of the *National Energy Board Rules of Practice and Procedure, 1995*, the Board considers it necessary to address them due to their serious nature.

The SBDFN alleges that the fact that the Board has scheduled final argument on the substantial merits of the Southern Lights application for 31 October 2007 implies that the Board has already determined the jurisdictional motion advanced by the SBDFN and apparently did so before receiving the submissions of the respondents and before the SBDFN reply.

The Board advises that no decision has been made on the Motion and will not be made until the Board has had an opportunity to fully consider the Motion and all of the submissions made by the parties. Should it grant the SBDFN Motion, the Board would take all necessary steps, including re-opening the hearing record, to implement its decision. Hearing argument on the merits of the application at this time does not preclude the Board from taking any required steps in that regard.

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As there is a further evidentiary session of the hearing scheduled for 29 October 2007, should any evidence pertaining to the Motion be adduced at that time, parties may make submissions regarding any impact the additional evidence may have on their positions with respect to the Motion during the scheduled argument. The SBDFN may reply to any new submissions made with respect to the Motion either immediately following the Applicants' counsel's Reply Argument, or through a written submission to be filed by no later than **noon, Calgary time, Friday, 2 November 2007**.

The Board wishes to emphasize that any additional submissions with respect to the Motion must be restricted to the impact of any new information that has been put on the record since the parties made their earlier submissions on the Motion. Matters that the SBDFN wishes to address that are outside the scope of the Motion must be addressed in accordance with the schedule outlined in the Board's procedural letter dated 22 October 2007.

With respect to the concerns raised over membership of the Southern Lights and the ACCE hearing panels, the SBDFN seems to suggest that the fact that the Southern Lights Panel Members were and are involved in separate proceedings on separate applications involving similar issues, forecloses their participation in the Southern Lights proceeding. The Board is of the view that this is an untenable position given, among other things, the Board's role as an expert quasi-judicial tribunal. The Board is cognizant of its responsibility to only consider evidence on the record of the Southern Lights proceeding.

As a result the Board has decided not to accede to the request of the SBDFN to recuse itself and will continue with the Southern Lights Hearing as scheduled.

Yours truly,

Claudine Dutil-Berry
Secretary of the Board

Appendix III

NEB Orders including Schedule A

XO-E101-02-2008

IN THE MATTER OF the *National Energy Board Act* (NEB Act) and the regulations made thereunder; and

IN THE MATTER OF an application pursuant to section 58 of the NEB Act dated 9 March 2007 by Enbridge Pipelines Inc. (EPI) for exemptions from sections 30, 31 and 47 of the NEB Act in respect of EPI's Line 2 Modifications, (the Project), filed with the National Energy Board under File OF-Fac-Oil-E101-2007-01 01.

BEFORE the Board on 13 February 2008.

WHEREAS the Board received applications dated 9 March 2007, from EPI and Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP and Enbridge Pipelines Inc. (collectively the Applicants) for the Southern Lights Project consisting of two sub-projects, the Diluent Pipeline Project and the Capacity Replacement Project;

WHEREAS the Board held a public hearing pursuant to Hearing Order OH-3-2007 in respect of the Southern Lights Project ;

AND WHEREAS, pursuant to the *Canadian Environmental Assessment Act* (CEA Act), the Board conducted an environmental screening of the Southern Lights Project and concluded that with the implementation of the Applicants' environmental protection procedures and mitigation measures and the NEB's recommendations the Southern Lights Project is not likely to cause significant adverse environmental effects;

AND WHEREAS the Project, as described in the attached Schedule A, is a part of the Capacity Replacement Project, with an estimated cost of $42 million;

AND WHEREAS the Project will involve modifications to existing Line 2 pipeline facilities and no new land rights will be required;

AND WHEREAS the Board has examined this application and considers it to be in the public interest to grant the relief requested therein;

IT IS ORDERED that, pursuant to section 58 of the NEB Act, the Project as identified in Schedule A, is exempt from the provisions of sections 30, 31, and 47 of the NEB Act, subject to the following conditions:

Unless otherwise specified in a condition, *construction* includes the clearing of vegetation, ground-breaking and other forms of right-of-way and station site preparation that may have an effect on the environment, but does not include activities associated with normal surveying operations or data collection activities.

General

1. EPI shall comply with all of the conditions contained in this Order unless the Board otherwise directs.

2. Project construction shall not commence until the issuance of the Certificate for the Light Sour Pipeline, which forms a part of the Southern Lights Project.

Engineering

3. EPI shall cause the approved Project to be designed, located, constructed, installed and operated in accordance with the specifications, standards and other information referred to in its application or as otherwise agreed to during the OH-3-2007 proceeding.

Environment

4. EPI shall implement or cause to be implemented all of the policies, practices, programs, mitigation measures, recommendations and procedures for the protection of the environment included in or referred to in its application or as otherwise agreed to during the OH-3-2007 proceeding or in its related submissions.

Commitments

5. EPI shall:

   (a) file with the Board and post on its Company website, at least 60 days before the planned start of construction, a table listing all commitments made by EPI during the OH-3-2007 proceeding related to the Project, conditions imposed by the NEB, and the deadlines associated with each; and

   (b) update the status of the commitments in (a) on its web site at least on a quarterly basis, advising the Board accordingly.

Landowner Complaints

6. EPI shall, for audit purposes, create and maintain records to chronologically track landowner complaints related to the Project. The landowner complaint records shall include:

   (a) the date the complaint was received from the landowner;

   (b) how the complaint was received (e.g., telephone, letter, email, etc.)

   (c) subsequent dates of all telephone calls, visits, correspondence, and the site monitoring/inspections, reports, etc;

(d) updated contact information for all parties involved in the complaint;

(e) detailed description of the complaint;

(f) date of resolution of complaint; and

(g) if no resolution, further action to be taken or an explanation why no further action is required.

Prior to Construction

Welding and Testing Procedures

7. EPI shall develop the joining programs for the Project and file these with the Board for approval at least 60 days prior to commencement of any welding activities to which the programs relate. Each joining program shall include:

(a) requirements for the qualification of welders;

(b) requirements for the qualification and duties of welding inspectors;

(c) the welding techniques and processes EPI would be using;

(d) the welding procedure specifications and procedure qualification records;

(e) the welding procedure specifications for welding on in-service pipelines (where applicable);

(f) the non-destructive examination (NDE) procedures, and supporting procedure qualification records, which detail the ultrasonic and/or radiographic techniques and processes EPI would be using, for each welding technique;

(g) the defect acceptance criteria for each type of weld (i.e. production, tie-in and repair);

(h) an explanation of how the defect acceptance criteria were determined; and

(i) any additional information which supports the joining program.

Construction Schedule

8. EPI shall file with the Board at least 60 days prior to construction, a detailed construction schedule for the Project identifying major construction activities and shall notify the Board of any modifications to the schedule as they occur.

Manuals

9. EPI shall file with the Board at least 60 days prior to construction of the Project a comprehensive health and safety plan for the Project.

During Construction

Archaeological and Heritage Resources

10. EPI shall, in the event that previously unidentified archaeological or heritage resources are discovered:

    (a) immediately cease work at the location of the discovery and notify responsible provincial authorities; and

    (b) resume work only after approval is granted by the responsible provincial authority.

Construction Progress Reports

11. EPI shall file with the Board, construction progress reports on a monthly basis between commencement and completion of construction of the Project, in a form satisfactory to the Board. The reports shall include information on the activities carried out during the reporting period, any environmental, safety and non-compliance issues, and the measures undertaken for the resolution of each issue.

Condition Compliance

12. Within 30 days of the date that the approved Project is placed in service, EPI shall file with the Board a confirmation, by an officer of the company, that the approved Project was completed and constructed in compliance with all applicable conditions of this Order. If compliance with any of these conditions cannot be confirmed, the officer of the company shall file with the Board details as to why compliance cannot be confirmed. The filing required by this condition shall include a statement confirming that the signatory to the filing is an officer of the company.

Expiration of Order

13. Unless the Board otherwise directs prior to 31 August 2009, this Order shall expire on 31 August 2009 unless construction in respect of the facilities has commenced by that date.

SCHEDULE A
Order XO-E101-02-2008

Enbridge Pipelines Inc. Application, dated 9 March 2007, pursuant to section 58 of the *National Energy Board Act*

Southern Lights Project – Line 2 Modification Facilities
File OF-Fac-Oil-E101-2007-01 01

Facilities Specifications

Construction Type	Modification
Facility Type	Instrumentation and Controls Equipment and Piping
Location	EPI's existing 22 pumps stations for Line 2, as listed above (in Alberta, Saskatchewan and Manitoba)
Description	Modifications to the following existing facilities: • Ultrasonic flow meter • Pressure control valves on discharge side of pumps • Emergency shutdown systems
Product	Crude oil
Maximum Operating Pressure	9 650 kPa

SCHEDULE A (continued)
Order XO-E101-02-2008

Location of Pump Station for Line 2			Pump Station Modifications	Modified Pump Units
Alberta	**Edmonton** SE 5-53-23 W4M - NE 32-52-23 W4M	KP 0.0	• Pumps modified and motor replaced • Additional DRA [(1)] unit	2.1 2.2
Alberta	**Kingman** SE 5-49-20 W4M	KP 51.1	• Pumps replaced • Relocated DRA unit	2.1 2.2
Alberta	**Strome** SW 2-46-15 W4M	KP 112.2	• Pumps replaced • Recommissioned DRA unit	2.1 2.2
Alberta	**Hardisty** SE 30-42-9 W4M	KP 175.4	• Pumps modified and motor replaced • Additional DRA unit	2.1 2.2
Alberta	**Metiskow** SE 1-40-5 W4M	KP 229.6	• Pumps replaced • Recommissioned DRA unit	2.3 2.4
Saskatchewan	**Cactus Lake** NE 32-26-27 W3M	KP 289.8	• Pump replaced • Recommissioned DRA unit	2.1
Saskatchewan	**Kerrobert** SE 34-33-22 W3M	KP 351.3	• Pumps modified and motors replaced • Relocated DRA unit	2.1 2.2 2.3
Saskatchewan	**Herschel** SE/SW 16-31-16 W3M	KP 413.6	• Pump replaced • Relocated DRA unit	2.1
Saskatchewan	**Milden** SE 6-29-10 W3M	KP 475.0	• Pumps replaced or modified and motor replaced • Relocated DRA unit	2.1 2.2 2.3

[(1)] DRA: drag reducing agent

SCHEDULE A (continued)
Order XO-E101-02-2008

Location of Pump Station for Line 2			Pump Station Modifications	Modified Pump Units
Saskatchewan	**Loreburn** SW 12-26-5 W3M	KP 538.9	• Pumps modified • Additional DRA unit	2.1 2.2
	Craik SE 10-23-29 W2M - NE 3-23-29 W2M	KP 590.7	• Pumps replaced • Additional DRA unit	2.1 2.2
	Bethune SE 22-19-24 W2M	KP 653.0	• Pumps replaced • Additional DRA unit	2.1 2.2
	Regina NE 32-17-19 W2M	KP 704.2	• Pumps replaced and new pump installed with new motor • Relocated DRA unit	2.1 2.2
	White City SE 1-17-17 W2M	KP 732.5	• Pump replaced and new pump installed with new motor • Relocated DRA unit	2.1
	Odessa SW 35-15-14 W2M	KP 762.0	• Pump replaced • Additional DRA unit	2.2
	Glenavon SW 22-14-9 W2M	KP 812.1	• Pumps replaced or modified • Relocated DRA unit	2.1 2.3 2.4
	Langbank SE/SW 2-13-3 W2M	KP 875.2	• Pump replaced • Relocated DRA unit	2.1
Manitoba	**Cromer** NE 17-9-28 WPM - SE 20-9-28 WPM	KP 958.8	• Additional DRA unit	-
	Souris NE/SE 8-8-20 WPM	KP 1040.0	• Recomissionned DRA unit	-
	Glenboro SE 3-7-14 WPM	KP 1103.3	• Additional DRA unit	-
	Manitou NW 17-4-8 WPM	KP 1165.1	• Additional DRA unit	-
	Gretna SE 8-1-1 WPM	KP 1242.4	• Additional DRA unit	-

ORDER XO-E101-03-2008

IN THE MATTER OF the *National Energy Board Act* (NEB Act) and the regulations made thereunder; and

IN THE MATTER OF an application pursuant to section 58 of the NEB Act dated 9 March 2007 by Enbridge Southern Lights GP on behalf of

Enbridge Southern Lights LP (ESL) for exemptions from sections 30, 31 and 47 of the NEB Act in respect of the Line 13 Reversal Facilities, (the Project), filed with the National Energy Board under File OF-Fac-Oil-E101-2007-01 01.

BEFORE the Board on 13 February 2008.

WHEREAS the Board received applications dated 9 March 2007, from Enbridge Pipelines Inc. and ESL (collectively the Applicants) for the Southern Lights Project consisting of two sub-projects, the Diluent Pipeline Project and the Capacity Replacement Project;

AND WHEREAS the Project, as described in the attached Schedule A, is a part of the Diluent Pipeline Project, with an estimated cost of $44 million;

AND WHEREAS the Board held a public hearing pursuant to Hearing Order OH-3-2007 in respect of the Southern Lights Project;

AND WHEREAS, pursuant to the *Canadian Environmental Assessment Act* (CEA Act), the Board conducted an environmental screening of the Southern Lights Project and concluded that with the implementation of the Applicants' environmental protection procedures and mitigation measures and the NEB's recommendations the Southern Lights Project is not likely to cause significant adverse environmental effects;

AND WHEREAS Line 13 would remain in low vapour pressure service and the Project does not involve an increase in maximum operating pressures;

AND WHEREAS the Project will take place within existing pump stations and valve sites on the Line 13 Right of Way and no new land rights are required;

AND WHEREAS the Board has examined this application and considers it to be in the public interest to grant the relief requested therein;

IT IS ORDERED that, pursuant to section 58 of the NEB Act, the Project as identified in Schedule A, is exempt from the provisions of sections 30, 31 and 47 of the NEB Act, subject to the following conditions:

Unless otherwise specified in a condition, *construction* includes the clearing of vegetation, ground-breaking and other forms of right-of-way and station site preparation that may have an effect on the environment, but does not include activities associated with normal surveying operations or data collection activities.

General

1. ESL shall comply with all of the conditions contained in this Order unless the Board otherwise directs.

2. Project construction shall not commence until the issuance of the Certificate for the Light Sour Pipeline, which forms a part of the Southern Lights Project.

Engineering

3. ESL shall cause the approved Project to be designed, located, constructed, installed, and operated in accordance with the specifications, standards and other information referred to in its application or as otherwise agreed to during the OH-3-2007 proceeding.

Environment

4. ESL shall implement or cause to be implemented all of the policies, practices, programs, mitigation measures, recommendations and procedures for the protection of the environment included in or referred to in its application or as otherwise agreed to during the OH-3-2007 proceeding or in its related submissions.

Commitments

5. ESL shall:

   (a) file with the Board and post on its Company website, at least 60 days before the planned start of construction, a table listing all commitments made by ESL during the OH-3-2007 proceeding, conditions imposed by the NEB, and the deadlines associated with each;

   and

   (b) update the status of the commitments in (a) on its web site at least on a quarterly basis, advising the Board accordingly.

Landowner Complaints

6. ESL shall, for audit purposes, create and maintain records to chronologically track landowner complaints related to the Project. The landowner complaint records shall include:

   (a) the date the complaint was received from the landowner;

   (b) how the complaint was received (e.g., telephone, letter, email, etc.)

(c) subsequent dates of all telephone calls, visits, correspondence, and the site monitoring/inspections, reports, etc;

(d) updated contact information for all parties involved in the complaint;

(e) detailed description of the complaint;

(f) date of resolution of complaint; and

(g) if no resolution, further action to be taken or an explanation why no further action is required.

Construction Schedule

7. ESL shall file with the Board at least 60 days prior to construction, a detailed construction schedule identifying major construction activities and shall notify the Board of any modifications to the schedule as they occur.

Manuals

8. ESL shall file with the Board at least 60 days prior to construction a comprehensive health and safety plan.

Welding and Testing Procedures

9. ESL shall develop the joining programs for the Project and file these with the Board for approval at least 60 days prior to commencement of any welding activities to which the programs relate, in preparation for Project. Each joining program shall include:

(a) requirements for the qualification of welders;

(b) requirements for the qualification and duties of welding inspectors;

(c) the welding techniques and processes ESL would be using;

(d) the welding procedure specifications and procedure qualification records;

(e) the welding procedure specifications for welding on in-service pipelines (where applicable);

(f) the non-destructive examination (NDE) procedures, and supporting procedure qualification records, which detail the ultrasonic and/or radiographic techniques and processes ESL would be using, for each welding technique;

(g) the defect acceptance criteria for each type of weld (i.e. production, tie-in and repair);

(h) an explanation of how the defect acceptance criteria were determined; and

(i) any additional information which supports the joining program.

During Construction

Archaeological and Heritage Resources

10. ESL shall, in the event that previously unidentified archaeological or heritage resources are discovered:

    (a) immediately cease work at the location of the discovery and notify responsible provincial authorities; and

    (b) resume work only after approval is granted by the responsible provincial authority.

Construction Progress Reports

11. ESL shall file with the Board, construction progress reports on a monthly basis between commencement and completion of construction, in a form satisfactory to the Board. The reports shall include information on the activities carried out during the reporting period, any environmental, safety and non-compliance issues, and the measures undertaken for the resolution of each issue.

Engineering Assessment and Potential Hydrotesting of Line 13

12. ESL shall file with the Board for approval, at least nine months prior to placing Line 13 into diluent service, an engineering assessment (EA) in accordance with the Canadian Standards Association Z662-07, *Oil and Gas Pipeline Systems* which evaluates the pipeline's fitness for purpose, for the proposed reversal of flow. The EA shall account for, but not be limited to:

    (a) a comparison of excavation findings with associated results from all crack in-line inspections (ILI) performed during current service, and with associated results from the most recent geometry ILIs;

    (b) a confirmation of the accuracy of the ILI tools, or measures undertaken to mitigate potential inaccuracies;

    (c) the pipeline condition after completion of repairs, including type and dimensions of remaining crack and geometry features;

    (d) a comparison of operation prior to reversal versus future service conditions, including cyclical loading estimates;

    (e) the estimated defect growth and time until failure, once Line 13 is reversed;

    (f) pipe design and material properties (such as toughness) of the various Line 13 portions;

    (g) transient analyses completed on Line 13;

(h) consequences of failure, with regard to pipe properties described in f); and

(i) other potential hazards that may be aggravated by the proposed reversal of Line 13.

In the event that the Board is not satisfied that the engineering assessment demonstrates that Line 13 may safely commence operation in diluent service, ESL shall be required to hydrotest all, or portions of Line 13. If hydrotesting is required, ESL shall file with the Board for approval its Pressure Testing Program at least four weeks prior to the commencement of pressure testing activities.

During Operation

Revised Engineering Assessment

No later than six months after placing Line 13 into diluent service, ESL shall submit to the Board a revised engineering assessment to account for actual operating pressure profiles and pressure cycle data gathered since the reversal of flow. As part of ESL's engineering assessment, estimated defect growth rates and in-line inspection intervals shall be adjusted accordingly.

Emergency Response Exercise

14. Within six (6) months after commencement of operation of the Project:

(a) ESL shall conduct an emergency response exercise at its South Saskatchewan River crossing and relevant downstream control points with the objectives of testing:
- emergency response procedures, including response times;
- training of company personnel;
- communications systems;
- response equipment;
- safety procedures; and
- effectiveness of its liaison and continuing education programs.

(b) ESL shall notify the Board, at least thirty (30) days prior to the date of the emergency response exercise, of the following:
- the date(s) and location(s) of the exercise;
- the type of exercise;
- the exercise scenario;
- the proposed participants in the exercise;
- the objectives of the exercise; and
- the evaluation criteria.

(c) ESL shall file with the Board, within sixty (60) days after the emergency response exercise outlined in (a), a final report on the exercise including:

- the results;
- how objectives were achieved;
- areas for improvement; and
- steps to be taken to correct deficiencies.

Condition Compliance

15. Within 30 days of the date that the approved Project is placed in service, ESL shall file with the Board a confirmation, by an officer of the company, that the approved Project was completed and constructed in compliance with all applicable conditions of this Order. If compliance with any of these conditions cannot be confirmed, the officer of the company shall file with the Board details as to why compliance cannot be confirmed. The filing required by this condition shall include a statement confirming that the signatory to the filing is an officer of the company.

Expiration of Order

16. Unless the Board otherwise directs prior to 31 August 2009, this Order shall expire on 31 August 2009 unless construction in respect of the facilities has commenced by that date.

SCHEDULE A
Order XO-E101-03-2008

Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP Application, dated 9 March 2007, Pursuant to section 58 of the *National Energy Board Act*

Southern Lights Project – Line 13 Reversal Facilities
File OF-Fac-Oil-E101-2007-01 01

<u>Facilities Specifications</u>

Construction Type	Modification	
Facility Type	Check Valves	
Location	KP 1244.6	(between United States border and Gretna station)
	KP 1213.5	(between stations Gretna and St. Leon)
	KP 1200.2	(between stations Gretna and St. Leon)
	KP 937.9	(between stations Cromer and Langbank)
	KP 890.6	(between stations Cromer and Langbank)
	KP 660.9	(between stations Regina and Craik)
Description	Modifications to six existing check valves : • reversal • reuse or replacement with new check valve • potential relocation along Line 13	
Product	Low vapour phase (LVP) products for diluent: • natural gas condensates • other light hydrocarbon products	

SCHEDULE A (continued)
Order XO-E101-03-2008

Location of Pump Station for Line 13			Pump Station Modifications			
			Inlet and outlet piping	DRA injection unit [1]	Delivery equipment and meters	Scraper traps [2]
Manitoba	**Gretna** SE 8-1-1 WPM	KP 1242.4	Reversed	New	-	-
	St. Leon SW 33-4-9 WPM	KP 1155.6	Reversed	-	-	-
	Glenboro SE 3-7-14 WPM	KP 1103.3	Reversed	-	-	-
	Souris NE/SE 8-8-20 WPM	KP 1040.0	Reversed	New	-	-
	Cromer NE 17-9-28 WPM - SE 20-9-28 WPM	KP 958.8	Reversed	New	-	Modified
Saskatchewan	**Langbank** SE/SW 2-13-3 W2M	KP 875.2	Reversed	-	-	-
	Glenavon SW 22-14-9 W2M	KP 812.1	Reversed	-	-	-
	Odessa SW 35-15-14 W2M	KP 762.0	Reversed	-	-	-
	Regina NE 32-17-19 W2M	KP 704.2	Reversed	-	-	Modified
	Craik SE 10-23-29 W2M - NE 3-23-29 W2M	KP 590.7	Reversed	-	-	-
	Loreburn SW 12-26-5 W3M	KP 538.9	Reversed	-	-	-
	Herschel SE/SW 16-31-16 W3M	KP 413.6	Reversed	-	-	-
	Kerrobert SE 34-33-22 W3M	KP 351.3	Reversed	-	New	Modified
Alberta	**Metiskow** SE 1-40-5 W4M	KP 229.6	Reversed	-	-	-
	Hardisty SE 30-42-9 W4M	KP 175.4	Reversed	New	New	-
	Kingman SE 5-49-20 W4M	KP 51.1	Reversed	-	-	-
	Edmonton SE 5-53-23 W4M - NE 32-52-23 W4M	KP 0.0	Pumps idled	-	New	-

(1) DRA: drag reducing agent
(2) The scraper trap facility at KP 899.9 near Kelso (Saskatchewan) will also be modified.

MO-03-2008

IN THE MATTER OF the *National Energy Board Act* (NEB Act) and the regulations made thereunder; and

IN THE MATTER OF an application by Enbridge Pipelines Inc. and Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP (ESL), collectively the Applicants, for leave to transfer certain mainline facilities (Line 13 facilities) from EPI to Enbridge Southern Lights LP, pursuant to paragraphs 74(1)(a) and 74(1)(b) of the NEB Act, and for an exemption pursuant to subsection 129(1.1), dated 9 March 2007, filed with the National Energy Board under File OF-Fac-Oil-E242-2007-01 01.

BEFORE the Board on 13 February 2008.

WHEREAS the Board received applications dated 9 March 2007, from the Applicants for the Southern Lights Project, consisting of two sub-projects, the Diluent Pipeline Project and the Capacity Replacement Project;

AND WHEREAS the transfer of the Line 13 facilities as described in the attached Schedule A, are part of the Diluent Pipeline Project:

WHEREAS the Board held a public hearing pursuant to Hearing Order OH-3-2007 in respect of the Southern Lights Project ;

AND WHEREAS the transfer is not subject to environmental assessment under the *Canadian Environmental Assessment Act*;

AND WHEREAS EPI owns the EPI mainline crude oil transmission system (Mainline) pursuant to Certificates of Public Convenience and Necessity OC-1 dated 9 May 1960, as amended by Order No. AO-1-OC-1 dated 28 October 1971; and OC-38 dated 18 March 1994;

AND WHEREAS the Applicants have agreed that, in consideration for EPI transferring Line 13 out of EPI Mainline service, Enbridge Southern Lights LP would pay to replace its capacity with the new LSr Pipeline and the Line 2 Modifications;

AND WHEREAS the Board's decisions on the two projects that comprise the Southern Lights Project are set out in its OH-3-2007 Reasons for Decision dated February 2008, and in this Order;

IT IS ORDERED, pursuant to paragraphs 74(1)(a) and 74(1)(b) of the Act and subject to the issuance of a Certificate for the Light Sour Pipeline, that leave for the transfer of the Line 13 facilities from EPI to Enbridge Southern Lights LP is granted;

IT IS FURTHER ORDERED THAT, pursuant to subsection 129(1.1), an exemption is granted from the *Oil Pipeline Uniform Accounting Regulations* requirement that, where facilities are purchased from an affiliated company, the original cost of the facilities and accumulated depreciation is recorded in the accounts of the purchasing company;

IT IS FURTHER ORDERED THAT, unless the Board otherwise directs, this Order shall expire by 1 July 2010 unless the Board has been advised that the transaction has been completed.

NATIONAL ENERGY BOARD

Claudine Dutil-Berry
Secretary of the Board

Schedule A
National Energy Board
Order MO-03-2008

EPI/ESL Application for
Leave to Transfer Certain Pipeline Facilities
File OF-Fac-Oil-E242-2007-01 01

Facilities

- 704.2 kilometres of 508 mm (NPS 20) outside diameter pipeline, 58.9 kilometres of
- 457 mm (NPS 18) outside diameter pipeline and 482.0 kilometres of 406.4 mm (NPS 16) outside diameter pipeline commencing at Edmonton, Alberta and terminating at the Canada / US border near Gretna, Manitoba
- 17 Line 13 Pump Stations
- 46 Block Valves and 6 Check Valves

Appendix IV

Light Sour Crude Oil Pipeline Certificate Conditions

General

Unless otherwise specified in a condition, *construction* includes the clearing of vegetation, ground-breaking and other forms of right-of-way and station site preparation that may have an effect on the environment, but does not include activities associated with normal surveying operations or data collection activities.

1. Enbridge Pipeline Inc (EPI) shall comply with all of the conditions contained in this Certificate unless the Board otherwise directs.

Engineering

2. EPI shall cause the approved Project to be designed, located, constructed, installed, and operated in accordance with the specifications, standards and other information referred to in its application or as otherwise agreed to during the OH-3-2007 proceeding.

Environment

3. EPI shall implement or cause to be implemented all of the policies, practices, programs, mitigation measures, recommendations and procedures for the protection of the environment included in or referred to in its application or as otherwise agreed to during the OH-3-2007 proceeding or in its related submissions.

Commitments

4. EPI shall:

   (a) file with the Board and post on its Company website, at least 60 days before the planned start of construction, a table listing all commitments made by EPI during the OH-3-2007 proceeding in relation to the Light Sour (LSr) pipeline, conditions imposed by the NEB, and the deadlines associated with each; and

   (b) update the status of the commitments in (a) on its web site at least on a quarterly basis, advising the Board accordingly.

Landowner Complaints

5. EPI shall, for audit purposes, create and maintain records to chronologically track landowner complaints related to the LSr pipeline. The landowner complaint records shall include:

   (a) the date the complaint was received from the landowner;

(b) how the complaint was received (e.g., telephone, letter, email, etc.)

(c) subsequent dates of all telephone calls, visits, correspondence, and the site monitoring/inspections, reports, etc;

(d) updated contact information for all parties involved in the complaint;

(e) detailed description of the complaint;

(f) date of resolution of complaint; and

(g) if no resolution, further action to be taken or an explanation why no further action is required.

Prior to Construction

Construction Schedule

6. EPI shall file with the Board at least 60 days prior to construction of the LSr Station Facilities, a detailed construction schedule identifying major construction activities and shall notify the Board of any modifications to the schedule as they occur.

7. EPI shall file with the Board at least 60 days prior to construction of the LSr Pipeline excluding the LSr Station Facilities, a detailed construction schedule identifying major construction activities and shall notify the Board of any modifications to the schedule as they occur.

Welding and Testing Procedures

8. EPI shall develop the joining program for the LSr Station Facilities and file these with the Board at least 60 days prior to commencement of any welding activities to which the programs relate. Each joining program shall include:

(a) requirements for the qualification of welders;

(b) requirements for the qualification and duties of welding inspectors;

(c) the welding techniques and processes EPI would be using;

(d) the welding procedure specifications and procedure qualification records;

(e) the welding procedure specifications for welding on in-service pipelines (where applicable);

(f) the non-destructive examination (NDE) procedures, and supporting procedure qualification records, which detail the ultrasonic and/or radiographic techniques and processes EPI would be using, for each welding technique;

(g) the defect acceptance criteria for each type of weld (i.e. production, tie-in and repair);

(h) an explanation of how the defect acceptance criteria were determined; and

(i) any additional information which supports the joining program.

9. EPI shall develop the joining program for the LSr Pipeline excluding the LSR Station Facilities and file these with the Board at least 60 days prior to the commencement of any welding activities to which the programs relate. Each joining program shall include:

(a) requirements for the qualification of welders;

(b) requirements for the qualification and duties of welding inspectors;

(c) the welding techniques and processes EPI would be using;

(d) the welding procedure specifications and procedure qualification records;

(e) the welding procedure specifications for welding on in-service pipelines (where applicable);

(f) `the non-destructive examination (NDE) procedures, and supporting procedure qualification records, which detail the ultrasonic and/or radiographic techniques and processes EPI would be using, for each welding technique;

(g) the defect acceptance criteria for each type of weld (i.e. production, tie-in and repair);

(h) an explanation of how the defect acceptance criteria were determined; and

(i) any additional information which supports the joining program.

Manuals

10. EPI shall file with the Board the following programs and manuals within the time specified:

(a) comprehensive health and safety plan related to the LSr Station Facilities–at least 60 days prior to construction of the LSr Station Facilities;

(b) comprehensive health and safety plan related to the LSr Pipeline excluding the LSr Station Facilities–at least 60 days prior to construction of the LSr Pipeline excluding the LSr Station Facilities; and

(c) field pressure testing program for the LSr Pipeline – at least 14 days prior to pressure test.

Environmental Protection Plan

11. EPI shall file with the Board for approval, at least 60 days prior to construction of the LSr Station Facilities, an updated project-specific Environmental Protection Plan (EPP). The EPP shall describe all environmental protection procedures, and mitigation and monitoring commitments related to the LSr Station Facilities, as set out in EPI's application or as otherwise agreed to during questioning, in its related submissions or through consultations with other government agencies. Construction of the LSr Station Facilities shall not commence until EPI has received approval of its EPP from the Board.

12. EPI shall file with the Board for approval, at least 60 days prior to construction of the LSr Pipeline excluding the LSR Station Facilities, an updated project-specific Environmental Protection Plan (EPP). The EPP shall describe all environmental protection procedures, and mitigation and monitoring commitments related to the LSr Pipeline excluding the LSr Station Facilities, as set out in EPI's application or as otherwise agreed to during questioning, in its related submissions or through consultations with other government agencies. Construction of the LSr Pipeline excluding the LSr Station Facilities shall not commence until EPI has received approval of its EPP from the Board.

Archaeology and Paleontology

13. EPI shall:

    (a) file with the Board, at least 60 days prior to the commencement of construction of the LSr Station Facilities, the results of the archaeological and paleontological investigations in the areas of the LSr Station Facilities; and

    (b) include the recommendations resulting from the archaeological and paleontological investigations.

14. EPI shall:

    (a) file with the Board, at least 60 days prior to the commencement of construction of the LSr Pipeline excluding the LSr Station Facilities, the results of the archaeological and paleontological investigations; and

    (b) include the recommendations resulting from the archaeological and paleontological investigations, including those for the Thornhill Burial Mounds, in the EPP.

During Construction

Archaeological and Heritage Resources

15. EPI shall, in the event that previously unidentified archaeological or heritage resources are discovered:

    (a) immediately cease work at the location of the discovery and notify responsible provincial authorities; and

    (b) resume work only after approval is granted by the responsible provincial authority

Construction Progress Reports

16. EPI shall file with the Board, construction progress reports on a monthly basis between commencement and completion of construction, in a form satisfactory to the Board. The reports shall include information on the activities carried out during the reporting period, any environmental, safety and non-compliance issues, and the measures undertaken for the resolution of each issue.

Depth of Cover Monitoring Program

17. EPI shall:

    (a) file with the Board for approval within 90 days of the commencement of operation of the LSr Pipeline, a Pipeline Depth Monitoring Program (PDMP) which would include:

        (i) the frequency of monitoring;

        (ii) the methodology to undertake monitoring;

        (iii) mitigation measures if locations shallower than 0.6 m of cover are discovered during monitoring, including the maximum time interval from the time EPI is made aware of the occurrence of low cover to the implementation of remediation efforts; and

        (iv) means by which findings of the PDMP will be communicated to affected landowners and how their comments will be included in the development of mitigation strategies;

    (b) integrate the PDMP into its Pipeline Integrity Management Program and submit a description of how this has been accomplished; and

    (c) provide a description of the consultation with landowners along the LSr route that was undertaken in the development of the PDMP.

Condition Compliance

18. Within 30 days of the date that the approved Project is placed in service, EPI shall file with the Board a confirmation, by an officer of the company, that the approved Project was completed and constructed in compliance with all applicable conditions of this Order. If compliance with any of these conditions cannot be confirmed, the officer of the company shall file with the Board details as to why compliance cannot be confirmed. The filing required by this condition shall include a statement confirming that the signatory to the filing is an officer of the company.

19. On or before the 31 of January of each of the first 5 years following the commencement of the operation of the LSr Pipeline, EPI shall file with the Board, and make available on its website for informational purposes, a post-construction environmental report that:

    (a) identifies on a map or diagram the location of any environmental issues which arose during construction;

    (b) discusses the effectiveness of the mitigation applied during construction and the methodology used to assess the effectiveness of mitigation;

    (c) identifies the current status of the issues identified (including those raised by landowners), and whether those issues are resolved or unresolved; and

    (d) provides proposed measures and timelines EPI shall implement to address any unresolved concerns.

    The report shall address, but not be limited to, issues pertaining to soil productivity on cultivated lands, weeds, reclamation of native prairie, water course crossings, and plant species of special concern.

Expiration of Certificate

20. Unless the Board otherwise directs prior to 31 August 2009, this Certificate shall expire on 31 August 2009 unless construction in respect of the facilities has commenced by that date.

Appendix V

Environmental Screening Report

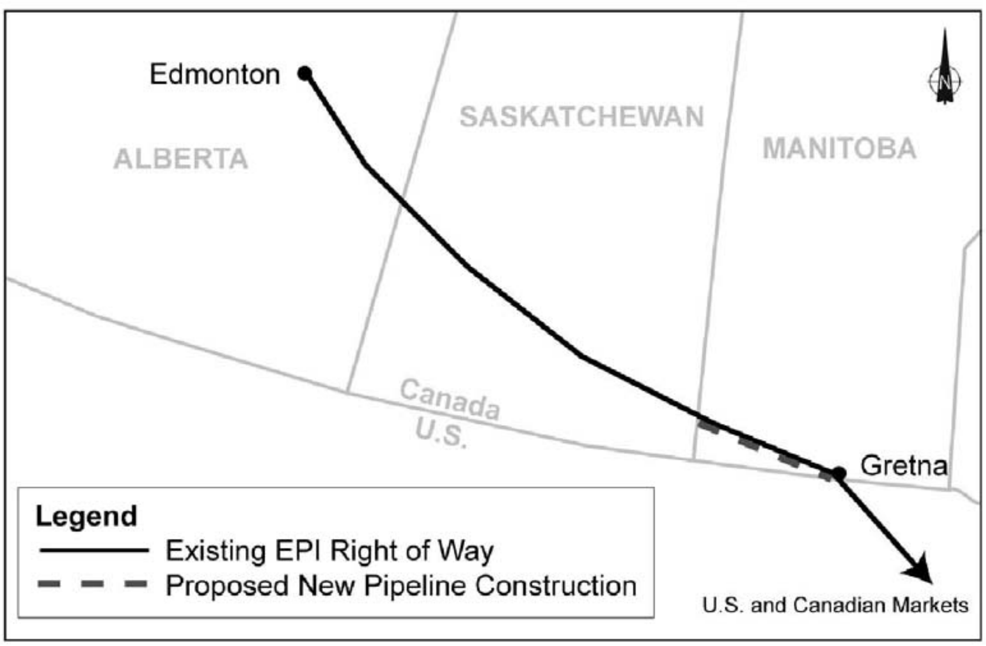
National Energy Board | Office national de l'énergie

ENVIRONMENTAL SCREENING REPORT

Pursuant to the *Canadian Environmental Assessment Act* (CEA Act)

Southern Lights Project

Applicants:	Enbridge Pipelines Inc. (EPI) Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP (ESL) EPI and ESL are collectively referred to as "the Applicants"		
Application Date:	9 March 2007 (Preliminary Information Package: 14 November 2006)	**CEA Act Registration Date:**	24 November 2006
National Energy Board File Numbers:	OF-Fac-Oil-E242-2007-01 01 OF-Fac-Oil-E242-2006-01 01	**Canadian Environmental Assessment Registry Number:**	06-01-23919
CEA Act Law List Triggers:	Section 52 and subsection 58(1) of the *National Energy Board Act* (NEB Act)	**CEA Act Determination Date:**	5 February 2008



Canada

SCREENING SUMMARY

The Applicants applied for the approval of a number of physical works and activities that would move diluent from Chicago to Edmonton through an existing pipeline, which currently moves crude oil in the opposite direction. To offset the potential loss of crude oil capacity, Enbridge Pipelines Inc. has also applied to construct approximately 288 km of new pipeline and modify existing pumping stations along its existing infrastructure.

The National Energy Board (Board or NEB) is the Federal Environment Assessment Coordinator for the applied-for project (Project). Transport Canada and Indian and Northern Affairs Canada have declared themselves as Responsible Authorities and Environment Canada, Department of Fisheries and Oceans, Natural Resources Canada and Health Canada declared themselves as Federal Authorities who were in the possession of specialist advice. Manitoba provincial agencies and a number of interested parties also participated in the environmental assessment process.

A number of potential adverse environmental effects of the Project, both bio-physical and socio-economic, were identified. Issues of public concern mainly focused on reduced soil capability and the potential for water contamination resulting from an accidental product release from the proposed pipeline and the existing pipeline to be reversed.

The NEB has considered information provided by the Applicants, government departments, and the public during its review of the Project. The Board is of the view that, provided all commitments and environmental protection measures made by the Applicants are upheld, and the Board's recommendations are implemented, the proposed Project is not likely to cause significant adverse environmental effects.

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LIST OF ACRONYMS AND ABBREVIATIONS

AB	Alberta
Alberta Clipper	Enbridge Pipelines Inc.'s proposed Alberta Clipper Expansion Project
Applicants	collectively, ESL and EPI
Board or NEB	National Energy Board
CEA Act	*Canadian Environmental Assessment Act*
DFO	Department of Fisheries and Oceans
DRA	drag reducing agent
EA	environmental assessment
EC	Environment Canada
EPI	Enbridge Pipelines Inc.
ERP	emergency response plan
ERCB	Energy Resources Conservation Board (Effective 1 January 2008, the Alberta Energy and Utilities Board was realigned into two separate regulatory bodies, the Energy Resources Conservation Board, which regulates the energy industry, and the Alberta Utilities Commission, which regulates the utilities industry.)
ESL	Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP
ESR or Report	Environmental Screening Report
FAs	Federal Authorities as defined in subsection 2(1) of the CEA Act
HC	Health Canada
INAC	Indian and Northern Affairs Canada
ha	hectare
km	kilometre
KP	kilometre post
LSr Pipeline	light sour crude oil pipeline and associated facilities
LSr Station Facilities	LSr Pipeline pumping and related facilities and pump station piping at three existing EPI pump station sites
m	metre
mm	millimetre
MPLA	Manitoba Pipeline Landowners Association
MB	Manitoba
MC	Manitoba Conservation
MIA	Manitoba Intergovernmental Affairs
MIT	Manitoba Infrastructure and Transportation
MWS	Manitoba Water Stewardship
MVA	Meewasin Valley Authority
NEB Act	*National Energy Board Act*
RAs	Responsible Authorities as defined in subsection 2(1) of the CEA Act

RoW	right of way
SK	Saskatchewan
SAPL	Saskatchewan Association of Pipeline Landowners
SARA	*Species at Risk Act*
TC	Transport Canada
US	United States

1.0 INTRODUCTION

1.1 Project Overview

Enbridge Pipelines Inc. (EPI) owns and operates the Canadian portion of a mainline pipeline system, which currently transports crude oil and petroleum products from Edmonton, Alberta (AB) to the Canada – United States (US) border near Gretna, Manitoba (MB) [Canada/US Border]. This system is comprised of a number of lines including Line 2 and Line 13, all of which extend into the US to reach American and Canadian market locations. Several existing pump stations and valve locations associated with the various lines occur along this right of way (RoW).

The Applicants[1] are proposing to construct and operate the Southern Lights Project (the Project) which, in Canada, would consist of the following three components:

1. construction and operation of a light sour crude oil pipeline, including associated infrastructure at pump stations (LSr Station Facilities), collectively referred to as the LSr Pipeline;
2. modifications to infrastructure on Line 2; and
3. conversion of the existing Line 13 from crude oil service to diluent service[2] and the subsequent reversal of the flow from south to north

The proposed work also requires the construction and operation of pipelines and facilities in the US; however, those works are beyond the scope of this Project.

1.2 Information Sources used in this ESR

This Environmental Screening Report (ESR) is based on information from the following sources:

- Project application (Volume I – Application, Volume II – Report on Environmental and Socio-Economic Assessment, and Volume III – Environmental Alignment Sheets)
- supplementary filings to the Project application;
- responses to information requests;
- various EPI manuals referenced in the Project application (e.g. Environmental Guidelines for Construction (December 2003), Waste Management Plan (October 2004);

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[1] The term "Applicants" includes both EPI and Enbridge Southern Lights GP on behalf of Enbridge Southern Lights LP (ESL). Although EPI owns and operates existing pipeline and associated facilities and will be constructing all the new facilities mentioned above, EPI will retain ownership of the Line 13 reversal component of the Project prior to any construction of that component. The term "Applicants" will be used in this report in circumstances where responsibility applies to both parties.

[2] Extra heavy oil and bitumen typically require diluent to thin raw production in order to meet specifications for transportation by pipeline. The Project's potential diluent supply sources fall into three broad categories: light hydrocarbon streams recycled from refineries; natural gasoline produced at natural gas liquids fractionators; and imports to North America of natural gasoline.

- submissions from the public and interested parties; and
- evidence submitted at the oral public hearing.

Filed information pertaining to the Project application can be found within 'Regulatory Documents' on the National Energy Board (NEB or Board) website (www.neb-one.gc.ca). For more details on how to obtain documents, please contact the Secretary of the NEB at the address specified in Section 11.0 of this ESR.

2.0 RATIONALE FOR THE PROJECT

The reversal and change of service of Line 13 would provide a new diluent transportation service from Chicago, Illinois to Edmonton, AB in order to meet the need for diluent related to the forecasted increase in production of Western Canadian heavy oil and bitumen between 2010 and 2025.

The construction of the proposed LSr Pipeline (additional capacity) and the modifications to Line 2 (increased pumping horsepower for increased throughput) are intended to compensate for the removal of Line 13 from crude oil service.

3.0 ENVIRONMENTAL ASSESSMENT PROCESS

An application for a number of approvals to construct and operate the Project, which is comprised of the three components outlined in Section 1.0 of this Report, was submitted to the Board on 9 March 2007 pursuant to section 52 and subsection 58(1) of the NEB Act.

The above-mentioned sections of the NEB Act are identified in the *Canadian Environmental Assessment Act* (CEA Act) *Law List Regulations,* thereby triggering the requirement for the preparation of this ESR.

3.1 Government Participation in the Environmental Assessment (EA) Process

The NEB is the Federal Environment Assessment Coordinator for this Project. Upon receipt of a Preliminary Information Package for the Project in November 2006, the NEB issued a federal coordination notification letter (FCN Letter), pursuant to section 5 of the CEA Act's *Regulations Respecting the Coordination by Federal Authorities of Environmental Assessment Procedures and Requirements* (Federal Coordination Regulations), to identify the potential involvement of federal departments in the EA process. The responses are summarized below:

Responsible Authorities (RAs)	Federal Authorities (FAs) in Possession of Specialist or Expert Information or Knowledge
Transport Canada*(TC) Indian and Northern Affairs Canada	Environment Canada (EC) Department of Fisheries and Oceans** (DFO) Natural Resources Canada Health Canada (HC)

*Transport Canada advises that it considers itself an RA until it makes the decision as to whether it may issue any approvals under the *Navigable Waters Protection Act* (NWPA) or the NEB Act. TC also stated that it intends to limit its involvement in the environmental assessment process to those components of the Project for which it has a likely CEA Act trigger, i.e. NWPA Section 5(1) or NEB Act Section 108 approval of the watercourse crossing at Oak Creek.

**DFO stated that it will not be commenting on the proposed broad scope of the project and will instead identify a scope of project that meets its responsibilities pursuant to the *Fisheries Act* and CEA Act and that directly relates to effects to fish and fish habitat resulting from construction of the pipeline. DFO stated that it will undertake a screening level assessment pursuant to CEA Act and the scope of project for the purposes of the DFO assessment will be associated with the water body crossings where Authorizations pursuant to the *Fisheries Act* are necessary.

The FCN Letter was also sent to provincial agencies in AB, Saskatchewan (SK) and MB. Saskatchewan Environment and Manitoba Conservation (MC) expressed interest in monitoring or participating in the EA process.

3.2 Feedback from the Public Including Government Agencies and First Nations

3.2.1 Submissions to the Board

Throughout the course of the EA process, the Board received several submissions pertaining to Project-related EA matters. The areas of primary concern are listed within Section 7.2 of this ESR.

3.2.2 Draft Scope of the EA

In mid-March 2007, the NEB sent a letter to RAs, FAs and interested provincial agencies inviting comments on the draft scope of the EA for the Project. Further, at the end of April 2007 the NEB, pursuant to subsection 18(3) of the CEA Act, conducted a public comment exercise on the scope of the EA including posting of the draft scope on the Canadian Environmental Assessment Registry for public comment.

3.2.3 NEB Hearing

Public oral hearings for the Project, pursuant to Hearing Order OH-3-2007, were held on three occasions: 13-14 August in Calgary, AB, 20-21 August in Regina, SK and 29 and 31 October in Calgary.

3.2.4 Draft ESR

On 13 December 2007, the NEB sent a letter to interested parties inviting comments on the draft ESR. Further, the draft ESR was posted on the Canadian Environmental Assessment Registry for public comment. A brief summary of public comments is provided in Section 7.3 and revisions were made to the ESR, as appropriate.

4.0 SCOPE OF THE ENVIRONMENTAL ASSESSMENT

The Scope of the Environmental Assessment (Scope) is composed of three parts:

1. Scope of the Project;
2. Factors to be Considered; and
3. Scope of the Factors to be Considered.

The Scope, as determined by the RAs in consultation with the FAs and the public, is included in Appendix 1 of this ESR and provides detailed information on these three parts. Appendix 1 includes a letter which provides the rationale for not making any changes in response to two submissions received from the public.

For this Project, the term "alternative means", as mentioned in Section 2.2 of the Scope, primarily refers to alternative routing options for the LSr Pipeline. These routing options are discussed in Section 9.1 of this ESR. Alternative construction methodologies (*e.g.* at watercourse crossings) are also considered within the context of alternative means.

Section 5.0 of this ESR expands upon the "Scope of the Project" and incorporates any updates and revisions made to the Project by the Applicants since the Scope was determined in June 2007.

5.0 DESCRIPTION OF THE PROJECT

Sections 5.1, 5.2 and 5.3 provide information for each Project component throughout the three phases of the Project: construction, operations and abandonment. Map 1 specifies the geographic location of the facilities involved.

5.1 Construction Phase

	Physical Works and/or Activities

LSr Pipeline
▪ Proposed pipeline Construction date: August/ fall 2008
	pipeline
	▪ Construction of a 288 kilometre (km) long, 508 millimetre (mm) outside diameter LSr Pipeline between Cromer, MB and the Canada/US Border
	▪ Approximately 260 km of the LSr Pipeline would be constructed within or adjacent to EPI's existing RoW in MB
	    ▪ The existing RoW, comprised of five pipelines 1, 2, 3, 4 and 13 varies in width; EPI proposes to achieve a consistent RoW width of 36.6 metre (m) after the completion of the LSr Pipeline; 110 km of existing RoW would not require any new permanent land; temporary workspace requirements would be approximately 22 m in width
	▪ Approximately 28 km of an 18.3 m wide RoW for the LSr Pipeline would be constructed outside of EPI's existing RoW in MB
	    ▪ 7.9 km of new RoW would be required east of the Souris River Valley
	    ▪ Approximately 20 km of new RoW at 10 locations
	▪ Approximate land area requirements: 377 hectares (ha) of permanent RoW and 697 ha of temporary work space

	Physical Works and/or Activities
	▪ Temporary workspace may be required at road, rail, foreign line, water crossings, areas where heavy grading is required, shoo-flies/access roads, equipment storage sites, pipe stockpile sites, bone yards, borrow pits and construction office sites ▪ Road and railway crossings would generally be bored ▪ Required activities would include some clearing, topsoil salvage, grading, trenching, backfilling, clean-up and reclamation; blasting may be required where bedrock is encountered ▪ Pressure testing using water in non-frozen conditions and either hot water or a water-methanol mixture during frozen conditions; test water would be disposed of in accordance with applicable regulatory requirements ▪ Several crossing methods would be used during watercourse construction such as isolation (e.g., dam and pump, flume), horizontal directional drill, bore and open cut ▪ Pipeline would be protected with cathodic protection ▪ 12 block valve sites would be installed within the LSr Pipeline RoW ▪ Minimum depth of cover in soil: 0.9 m of subsoil *LSr Station Facilities* ▪ At each of three existing pump stations*, EPI would install electrically-driven pump units and electrical services buildings. Scraper trap facilities and a new drag reducing agent (DRA) injection unit would be installed at Cromer
Line 2 Modifications ▪ Proposed Construction date: 2008	▪ Installation, relocation or recommissioning of DRA injection units at 22 existing pump stations* ▪ Pump and motor modifications, replacements and/or installations at 17 existing pump stations * ▪ No new lands or RoW are required ▪ Hydrostatic testing may be conducted

Line 13 Reversal
▪ Timeframe: July 2009 to June 2010
	▪ Modifications to piping at 17 existing pump stations *
	    ▪ Existing pumps would be reversed at all stations except Edmonton where pumps would be idled
	    ▪ Installation of DRA injection units at four existing pump stations
	▪ Installation of delivery metering and connections at three existing pump stations
	▪ Modifications to four existing scraper traps within existing pumping stations
	▪ Modifications to six existing check valves along Line 13
	▪ No new lands or RoW are required
	▪ Hydrostatic testing may be conducted

*** See Appendix 2 for the Locations of the Pump Stations**

5.2 Operations Phase

The LSr Pipeline is expected to be in service upon completion of construction and the facilities associated with the Line 2 Modifications are expected to be in service prior to or within that timeframe. Line 13 is expected to be in diluent service by mid-2010. The service life of the Project, as a whole, is anticipated to extend beyond 50 years.

The following outlines information related to the Operations phase of the various components of the Project:

LSr Pipeline

- Regular aerial and ground line patrols to inspect for environmental monitoring issues, damage to pipe or permanent erosion control structures, RoW encroachments, exposed pipe, erosion/ wash-out areas and sparse vegetation; pipeline markers and signs would also be inspected
- Running regular in-line inspection tools to identify integrity problems
- Maintenance digs, as necessary

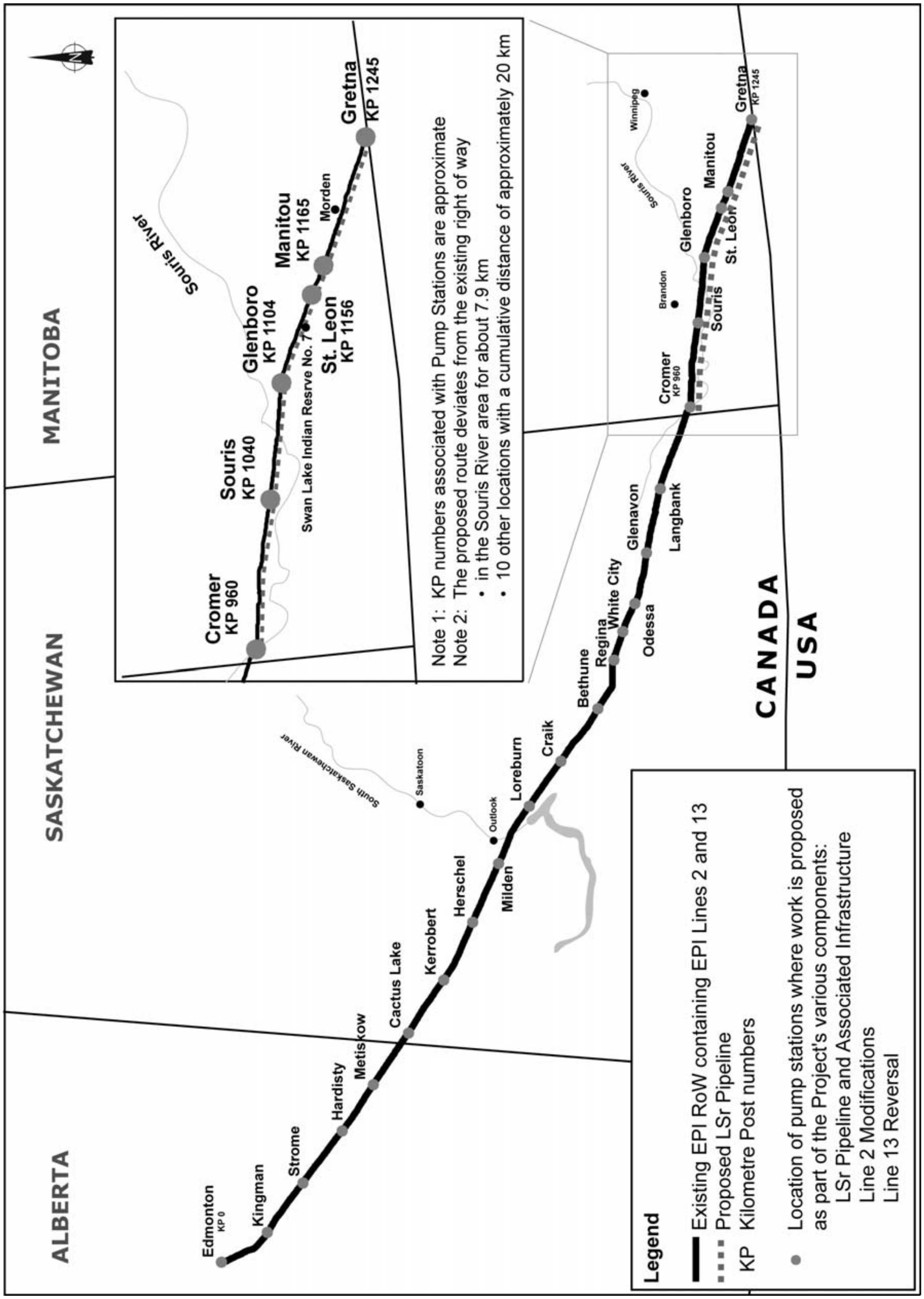
Line 2 Modifications, Line 13 Reversal, and LSr Station Facilities

- Regular inspections of permanent facilities such as pump stations; scraper traps would be inspected at least once per week
- Vegetated areas around permanent facilities would be periodically mowed and gravel may be occasionally added to the sites and on access roads
- There are no process combustion sources associated with the pipeline system and all pumps are driven by electric motors
- New and modified existing pumps and motors would be in compliance with the requirements of the Alberta Energy and Utilities Board's Noise Directive 038[3], hereinafter referred to as ERCB Directive 038: Noise Control
- EPI has a groundwater monitoring system at all but eight pumping stations; the Applicants have committed to installing groundwater monitoring systems at the eight remaining stations in the first year after the Project construction is completed

5.3 Abandonment Phase

At the end of the service life of the Project, an application pursuant to paragraph 74(1)(d) of the NEB Act would be required for its abandonment, at which time the environmental effects of the proposed abandonment activities would be assessed by the NEB under both the NEB Act and the CEA Act. It is anticipated that many of the effects associated with abandonment would likely be similar to those associated with construction or operation of the Project.

3 Effective 1 January 2008, the Alberta Energy and Utilities Board was realigned into two separate regulatory bodies, the Energy Resources Conservation Board (ERCB), which regulates the energy industry, and the Alberta Utilities Commission, which regulates the utilities industry. Consequently, the title of this Directive has been changed to "ERCB Directive 038: Noise Control".



Southern Lights Project
ALBERTA
SASKATCHEWAN
MANITOBA
CANADA
USA
Edmonton
KP 0
Kingman
Strome
Hardisty
Metiskow
Cactus Lake
Kerrobert
Herschel
Milden
Outlook
Saskatoon
South Saskatchewan River
Loreburn
Craik
Bethune
Regina
White City
Odessa
Glenavon
Langbank
Cromer
KP 960
Souris
Brandon
Glenboro
St. Leon
Manitou
Winnipeg
Souris River
Gretna
KP 1245
Cromer
KP 960
Souris
KP 1040
Swan Lake Indian Resrve No. 7
Glenboro
KP 1104
St. Leon
KP 1156
Manitou
KP 1165
Morden
Gretna
KP 1245
Souris River
Note 1: KP numbers associated with Pump Stations are approximate
Note 2: The proposed route deviates from the existing right of way
• in the Souris River area for about 7.9 km
• 10 other locations with a cumulative distance of approximately 20 km
Legend
Existing EPI RoW containing EPI Lines 2 and 13
Proposed LSr Pipeline
KP Kilometre Post numbers
Location of pump stations where work is proposed as part of the Project's various components:
LSr Pipeline and Associated Infrastructure
Line 2 Modifications
Line 13 Reversal

Map 1

6.0 DESCRIPTION OF THE ENVIRONMENT

6.1 LSr Pipeline Route

The description of the environment is based on information contained in a number of sources including:

- literature reviews;
- field studies performed for the EPI Terrace Phase 1 project, pertaining to soils, wildlife and vegetation, dating back to the 1990s;
- field studies (done mainly in 2006) in areas where:
  - areas deviated from the Terrace Phase 1 route,
  - the LSr Pipeline route segments did not form part of Terrace Phase 1 project, and
  - areas of known environmental importance in the vicinity of the LSr Pipeline route based on the results completed for Terrace Phase 1; and
- detailed surveys for a number of disciplines such as soils, wildlife, rare plants, fish, and wetlands, undertaken in 2007 for those areas where there were known knowledge gaps from previous field work.

The spatial extent of the detailed field surveys varied depending on the discipline. For example, wildlife and wildlife habitat surveys were conducted along segments of the proposed pipeline route that traverse native vegetation such as native prairie, bush and bush-pasture greater than 100 m in length, soil surveys were undertaken on previously non-surveyed areas, and weed surveys were performed over virtually the full length of the LSr Pipeline route.

EPI stated that the objectives of its field surveys included: the identification of species or issues; developing a description of habitat; and/or assisting with the development of practical and effective mitigative measures.

As EPI was not able to access all areas for the detailed surveys in 2007, EPI has committed to undertake surveys in 2008 and has stated that it would complete and submit the survey results to the NEB and other appropriate agencies prior to construction. Regarding some surveys such as the late summer rare plant surveys, EPI stated that the results would be submitted to the NEB and appropriate agencies 10 days prior to construction in those areas where the surveys were performed. EPI has conducted a number of late summer rare plant surveys along various segments of the LSr Pipeline route totaling approximately 20 km and has committed to conduct additional surveys in 2008 totaling approximately 10 km.

Land Use

- Land use along the proposed route consists of 68.4% cultivated land, 11.6% hay land, 9.9% pasture, 4.5% bush and bush/pasture, 5% native prairie and the remaining 0.6% disturbed lands.
- Existing infrastructure and activities in the area include oil and gas activity, roads, rail lines, agriculture, power lines and wind farms. Proposed projects include EPI’s Alberta

Clipper Expansion (Alberta Clipper), Southern Access and Line 4 Extension projects, TransCanada's Keystone Pipeline Project and various wind generation projects.

Terrain and Soils

- Flat to rolling terrain; steep slopes are encountered at the valleys associated with some of the watercourse crossings (*e.g.* Deadhorse Creek).
- No bedrock within trench depth was encountered during recent soil surveys.
- The proposed route does not encounter any areas of permafrost or earthquake-prone areas.
- Much of the proposed route traverses clay-textured soils prone to rutting and compaction during wet conditions; coarse-textured soils are also commonly encountered and are prone to trench sloughing and wind erosion.
- Soils on native prairie land are susceptible to rutting and sod/soil pulverization.
- Approximately five percent of the proposed route encounters saline and/or sodic soils.
- Known site of contamination at KP 1154.8 and other sites along the proposed route where there have been spills and leaks during past farming activities on cultivated and hay lands. (Refer to Section 9.3.1.1, under the heading, “Discovery of existing contaminated soils” for details on this issue.)

Fish and Fish Habitat

- A total of 26 watercourses would be crossed by the proposed LSr Pipeline. In addition, 17 drainages with undefined channels and limited fisheries value were identified along the proposed route.
- Ten of the moderate and larger watercourses along the route have the potential to support spring spawning sports fish; 23 species were captured during sampling and there are 20 additional species that could be potentially present.
- The Souris River is anticipated to exhibit year-round stream flow; however, many of the other watercourses crossed by the proposed route may be dry, frozen to the bottom or reduced to negligible flows during the winter.

Aquifers

- There are 17 sand and gravel aquifers along the proposed route. The following four aquifers would be crossed by the proposed LSr Pipeline route: Oak Lake (KP 975 to 1034), Assiniboine Delta (KP 1080 to 1110), Winkler (KP1207 to 1219), and an aquifer with a high groundwater table near the Swan Lake Indian Reserve No. 7.

Wetlands

- The proposed route crosses 83 km of wetland habitat, with less than 1 km crossing shallow open water wetlands and 82 km crossing low-lying prairie and wet meadow wetlands.
- Wetland areas with special conservation status include: the Oak Lake/Plum lakes, Important Bird Area (KP 987.0 to 1004.0); a Game Bird Refuge (KP 984.9 to 990.1); two Ducks Unlimited wetland projects (KP 1052.0 to 1053.7 and KP 1174.3 to 1174.8); two Manitoba Habitat Heritage Corporation (MHHC) Conservation Agreement areas (KP 1052.1 to 1052.9 and KP 1056.2 to 1057.0); and two North American Waterfowl Management Plan designated priority areas (KP 960.0 to 977.1 and KP 1052.0 to 1063.0).

Vegetation

- Most of the lands along the proposed route have been broken or cleared for agricultural purposes; however, remnant native vegetation (ranging from fescue grasslands to trembling aspen and/or bur oak forests) can be found on soils unsuitable for farming or where topographic constraints would restrict farming practices.
- A total of 70 weeds of concern were observed along the segments of the proposed route surveyed in 2007.
- Approximately 131 ha of native vegetation consisting of 59 ha of native prairie and 72 ha of bush and bush-pasture would be disturbed or cleared during construction.

Air Quality

- The proposed route is located in an area that is relatively undisturbed by industrial and commercial development which contributes to a high baseline air quality.

Wildlife and Wildlife Habitat

- The ecoregion also provides a major breeding habitat for waterfowl and includes habitat for white-tailed deer, coyote, snowshoe hare, cottontail, red fox, northern pocket gopher, ground squirrel black bear, moose, beaver, rabbit and bird species like sharp-tailed grouse, black-billed magpie and ruffed grouse.

Species at Risk, as listed on Schedule 1 of the Species at Risk Act (SARA)

- Lands in the vicinity of the proposed route may support the preferred habitat for the following 15 species listed on Schedule 1 of SARA: silver chub, hairy prairie clover, western spiderwort, small white lady's slipper, prairie skink, piping plover, grey fox, least bittern, loggerhead shrike, peregrine falcon, Sprague's pipit, Dakota skipper, yellow rail, northern leopard frog, and monarch butterfly.

- Sprague’s pipit and monarch butterfly were the only SARA species observed within the footprint of the proposed route during the 2007 surveys; northern leopard frog and peregrine falcon have been previously identified along the proposed route.
- Although maple leaf mussel, which is scheduled to be added to Schedule 1 of SARA, has documented occurrences in the Assiniboine River, it was not present in samples collected from the Souris River at the LSr Pipeline crossing.

Species of Concern (Species that are listed in SARA, other than on Schedule 1, and other federally/provincially listed species)

- Lands along the proposed route may support the preferred habitat of about 30 wildlife and fish species and approximately 85 vegetation species that are listed in SARA, other than on Schedule 1, or otherwise federally/provincially listed.
- American bittern, black tern, grasshopper sparrow, red-tailed hawk, short-eared owl and Swainson’s hawk were species of concern observed within the footprint of the proposed route during 2007 surveys and plains spadefoot toad, red-headed woodpecker, smooth green snake, snapping turtle, merlin, sprey and double-crested cormorant were observed in previous surveys.
- Based on the 2007 surveys, the following vegetative species of concern were observed: golden bean, sand bluestem, Schweinitz’s flatsedge, and Nuttall’s sunflower. Yellow Indiangrass, an uncommon species but not listed as rare in MB, was also observed. Seneca root was observed in previous surveys.

Socio-Economic

- Approximately 0.9 km of the proposed route traverses Swan Lake Indian Reserve No. 7 and is used for hay production.
- There are 537 water wells in the quarter sections traversed by the proposed route which are mainly used for domestic and livestock purposes.

Heritage Resources

- There are 18 previously recorded archaeological sites in the general vicinity of the proposed route including the Thornhill Burial Mounds.
- A number of areas along the proposed route have been identified as having high potential for containing historical resources.

Current Traditional Land and Resource Use

- The proposed LSr Pipeline traverses Treaty No. 1, Treaty No. 2, Treaty No. 4 and Treaty No. 6 lands as well as lands claimed by Dakota First Nations and Métis people as traditional territory.

6.2 Pump Stations for all Three Project Components and Six Check Valve Sites on Line 13

The following description is representative of all existing pump stations and the six check valve sites on Line 13 where work would be conducted as part of the Project. All work would be conducted within the confines of each facility.

- Previously disturbed, fenced industrial sites
- Lacking topsoil, vegetation and suitable habitat for wildlife (including for species at risk)
- With the exception of Edmonton, AB, there are no watercourses within any of the station sites
- Other than at Craik and Glenavon, SK, there are no wetlands within 30 m of the station sites
- The pump stations are currently sources of ongoing operational noise; however, noise from pumps and motors comply with ERCB Directive 038: Noise Control

7.0 COMMENTS FROM THE PUBLIC RELATED TO ENVIRONMENTAL AND SOCIO-ECONOMIC MATTERS OF THE PROJECT

7.1 Project-Related Issues Raised through Consultation Conducted by the Applicants

During the preparation of its Environmental and Socio-Economic Assessment for the Project, the Applicants consulted with a number of sources including the general public, landowner associations and federal, provincial and local government agencies. This information contributed to the identification of potential adverse environmental effects, issues of concern and the development of mitigation measures. The majority of issues and questions raised through the consultation efforts were resolved by the Applicants throughout the course of its application process. Some issues were also raised through submissions directly to the Board and those issues are included in Section 7.2.

7.2 Project-Related Issues Raised in Comments Received by the NEB

Several submissions from the public, landowner associations and various levels of government were received by the Board. They outlined a number of potential environmental effects. Those effects were categorized by environmental elements as outlined below.

Environmental Element of Interest	Interested Party		
	Government Agencies (federal, provincial, regional, local)	Public: (Individuals, Landowner associations, conservation groups)	Aboriginal Groups
Wildlife	X		
Species at Risk	X		
Wetlands	X		
Fish and Fish habitat	X		
Vegetation	X		
Soils	X	X	
Health	X		
Human Occupancy and Resource Use	X	X	
Heritage Resources			X
Current Traditional Land and Resource Use			X
Accidents and Malfunctions	X	X	
Cumulative Effects		X	

Information and concerns raised through the submissions have been incorporated within Section 9.0 of this Report.

7.3 Comments Received by the NEB on the draft ESR

Following the release of the draft ESR, a number of comments were received from EC, HC, TC, INAC, DFO, MC, Manitoba Water Stewardship (MWS), and Manitoba Intergovernmental Affairs (MIA). The Applicants also provided comments, including responses to a number of the comments made by the various government agencies.

Appendix 3 provides a summary of the comments, some of which resulted in wording changes to the ESR. Explanations have been included for those comments that did not result in changes to the ESR.

The Board has also made minor wording changes within the ESR for clarity and consistency.

Regarding its involvement with the CEA Act process, INAC stated that it may decide to conduct its own environmental screening report which would be limited to the scope of INAC's mandate or jurisdiction (Swan Lake Reserve land), by using the information provided in the NEB's ESR.

8.0 THE NEB'S ENVIRONMENTAL ASSESSMENT METHODOLOGY

In assessing the environmental effects of the Project, the NEB used an issue-based approach. Alternative LSr Pipeline routing considerations are discussed in Section 9.1. In its analysis within Section 9.2, the NEB identified interactions expected to occur between the proposed project activities and the surrounding environmental elements. Also included were the consideration of potential accidents and malfunctions that may occur due to the Project and any change to the Project that may be caused by the environment. If there were no expected element/Project interactions, then no further examination was deemed necessary. Similarly, no further examination was deemed necessary for interactions that would result in positive or neutral potential effects. In circumstances where the potential effect was unknown, it was categorized as a potential adverse environmental effect.

Section 9.3.1 provides an analysis for all potential adverse environmental effects that are normally resolved through the use of standard design or mitigation measures. In Section 9.3.2, the Board has identified certain potential adverse environmental effects for detailed analysis based on public concern or the use of non-standard design or mitigation measures. Appendix 4 specifies the ratings for criteria used in evaluating significance.

Section 9.4 provides discussion on inspection while Section 9.5 addresses cumulative effects. Section 9.6 addresses follow-up programs and Section 9.7 lists recommendations for any subsequent regulatory approval of the Project.

9.0 ENVIRONMENTAL EFFECTS ANALYSIS

9.1 Routing of the LSr Pipeline

Routing of the new LSr Pipeline was influenced by EPI's desire to minimize the amount of new land disturbance, avoid any areas of high environmental sensitivity and maximize operational efficiency.

The proposed LSr Pipeline route parallels the existing EPI pipeline corridor for approximately 90% of its length.

In a letter of comment, EC recommended that the proponent provide an alternate route that would avoid major wetland complexes. Subsequently, EPI stated that it understood that the rerouting request was primarily based on concerns about potential spills as opposed to potential damage caused by construction. Section 9.3.2.2 outlines EPI's mitigation measures to address this issue.

EPI identified a number of route realignments which are areas where the proposed route deviates from the existing EPI corridor, which are discussed below.

9.1.1 Souris River Route Realignment

Due to the encroachment on a farm yard within the Souris River area, EPI deviated approximately 7.9 km from its existing corridor.

At this location, EPI identified two route alternatives:

- Route Alternate 1: approximately 7.4 km long, entailing new RoW for approximately 23% of its total length; there is slope instability along a portion of the route; the pipeline would cross a highway using a boring technique at one location.
- Route Alternate 2: approximately 7.9 km long and entails new RoW for its entire length; there are no slope stability issues along the route; the pipeline would cross a highway using a boring technique at two locations.

EPI selected Route Alternate 2 to avoid slope stability issues.

Manitoba Infrastructure and Transportation (MIT), in a letter of comment, stated that it preferred Alternate Route 1 because it minimized the number of highway crossings. MIT noted the following requirements: that provincial road and highway crossings shall be bored; that any disturbance to the RoW shall be repaired and returned to pre-existing conditions; and that erosion controls shall be used where, according to MIT, erosion potential is high. EPI has committed to meet these requirements.

9.1.2 Other Route Realignments

Additionally, EPI's proposed route deviates from the existing corridor at 10 locations along approximately 20 km of the proposed 288 km route. Reasons for these deviations include avoidance of wetlands, shelterbelts, burial grounds and/or existing infrastructure. The linear distance of the proposed realignments ranges from tens of meters to about 300 m.

EPI stated that no potential impacts were identified along the proposed realignments which have not been previously addressed in its application. EPI further stated that the proposed route realignments do not alter the conclusions with respect to the significance of environmental effects.

9.1.3 Views of the Board

The Board is of the view that paralleling the existing EPI corridor as much as possible minimizes the potential environmental effects. The Board finds that the proposal to widen an existing pipeline RoW would minimize environmental and socio-economic effects compared to constructing the project on lands previously undisturbed by pipeline activity. Further, pipeline surveillance and maintenance activities can be conducted more efficiently within a common RoW than for two RoWs that are geographically separated.

Regarding the Souris River route realignment, the Board is of the view that EPI's selection of Alternate Route 2 would minimize potential environmental effects due to the elimination of the slope instability noted for Alternate Route 1. Although the Board acknowledges MIT's preference of Alternate Route 1 since it involves only one road crossing, the Board is of the view that EPI's proposed use of standard boring techniques would have little to no effect on the ongoing operation of highways. However, prior to any boring operation, the Board would expect EPI to consult with MIT and work toward resolving outstanding issues that may arise.

Regarding the other route realignments referred to above, the Board is of the view that EPI's proposed routing is appropriate and would likely result in lesser environmental effects as the deviations avoid environmentally sensitive areas as identified by EC, address concerns raised by landowners, and avoid infrastructure such as houses, shelterbelts or oil and gas facilities. The Board notes that the subsequent NEB detailed route process could also be used to address outstanding routing issues, if necessary.

If the Project is approved, further deviations, changes or alterations to the applied-for route would require an application to the NEB.

9.2 Project – Environment Interactions

(The interactions are primarily associated with the LSr Pipeline; however, as indicated, some may also apply to pumping and valve stations)

	Environmental Element	Project Inter-action?	Description of Interaction (How, When, Where)	Type of Potential Effect(s)	Potential Adverse Environmental Effect	Mitigation Discussed in: Section 9.3.1	Mitigation Discussed in: Section 9.3.2
Bio-Physical	Terrain stability	Y	▪ Clearing, grading, excavation and backfilling along the RoW	Adv	▪ Terrain instability	X	
	Soil and Soil Productivity	Y	▪ Clearing, grading, excavation and backfilling along the RoW and pump stations ▪ Use of construction equipment and vehicles	Adv	▪ Soils capability (surface/sub-soil mixing, soil erosion, saline soils, presence of stones in sub- and top soil, pulverization, compaction, wet conditions) on		
					○ Non-agricultural lands	X	
					○ Agricultural lands		X
					▪ Discovery of existing contaminated soils	X	
	Vegetation	Y	▪ Clearing, grading, excavation and backfilling along the RoW ▪ Use of construction equipment and vehicles	Adv	▪ Alteration/disturbance of native prairie	X	
					▪ Alteration of vegetation important to wildlife	X	
					▪ Introduction/spreading of weeds on the LSr Pipeline RoW	X	
					▪ Loss of ornamental trees, windbreaks and shelterbelts	X	
	Water Quality and Quantity	Y	▪ Clearing, grading, excavation, backfilling and blasting along the RoW ▪ Hydrostatic testing of pipelines	Adv	▪ Alteration of natural drainage patterns	X	
					▪ Reduction in surface water quality	X	
					▪ Disruption of water well flows	X	
					▪ Disruption of springs	X	
	Fish and Fish Habitat	Y	▪ Clearing, grading, excavation and backfilling at stream crossings along the RoW ▪ Use of equipment and vehicles during construction and operations	Adv	▪ Fish mortality and the disturbance or alteration of fish habitat, resulting from ○ Disturbance of riparian vegetation ○ Alteration of instream habitat ○ Increased suspended solid concentrations during instream construction ○ Blockage of fish movements ○ Contamination from spills ○ Bank instability at the crossing sites leading to bank erosion	X	

	Environmental Element	Project Inter-action?	Description of Interaction (How, When, Where)	Type of Potential Effect(s)	Potential Adverse Environmental Effect	Mitigation Discussed in: Section 9.3.1	Section 9.3.2
	Wetlands	Y	▪ Clearing, grading, excavation and backfilling at stream crossings along the RoW ▪ Use of equipment and vehicles during construction and operations	Adv	▪ Alteration of wetlands (habitat, hydrologic and/or water quality function)	X	
	Wildlife and Wildlife Habitat	Y	▪ Clearing, grading, excavation and backfilling along the RoW and some pump stations ▪ Use of equipment and vehicles during construction and operations	Adv	▪ Alteration of wildlife habitat ▪ Sensory disturbance and/or displacement of wildlife ▪ Mortality due to vehicle/wildlife collisions on access roads and along the RoW ▪ Mortality due to the physical disturbance of undiscovered nests, burrows, dens or other localized habitat on the RoW	X X X X	
	Species at Risk (federal)	Y	▪ See wildlife, vegetation and fish elements	Adv	▪ Disturbance, alteration of habitat and /or mortality or destruction to species at risk (wildlife, fish and/or vegetation)	X	
	Species of Special Status (provincial, territorial, local)	Y	▪ See wildlife, vegetation and fish elements	Adv	▪ See wildlife, vegetation and fish elements	X	
	Air Quality	Y	▪ Clearing, grading, excavation and backfilling along the RoW ▪ Use of equipment and vehicles during construction and operations ▪ Operations at pumping facilities: space heating of buildings; fugitive or process emissions	Adv	▪ Vehicle Equipment Emissions ▪ Dust ▪ Smoke from burning of slash ▪ Trace levels of greenhouse gases	X X X X	
Socio-Economic	Human Occupancy/ Resource Use	Y	▪ Clearing, grading, excavation and backfilling along the RoW ▪ Use of equipment and vehicles during construction and operations	Adv	▪ Disturbance to agricultural and ranching operations	X	
	Heritage Resources	Y	▪ Clearing, grading, excavation	Adv	▪ Disturbance/destruction of heritage resources	X	
	Current Traditional Land and Resource Use	U	▪ Clearing, grading, excavation and backfilling along the RoW ▪ Use of equipment and vehicles during construction	Adv	▪ Loss or alteration of traditional sites ▪ Disruption or inability to carry on traditional activities	X X	

	Environmental Element	Project Inter-action?	Description of Interaction (How, When, Where)	Type of Potential Effect(s)	Potential Adverse Environmental Effect	Mitigation Discussed in: Section 9.3.1	Mitigation Discussed in: Section 9.3.2
	Socio and Cultural Well-being	N					
	Human Health/ Aesthetics	Y	▪ Use of equipment and vehicles during construction and operations ▪ Ongoing operation of pumping facilities	Adv	▪ Loss of enjoyment of property or human health effects caused by noise	X	
Other	Accidents/ Malfunctions	Y	▪ Clearing, grading, excavation and backfilling along the RoW and pump stations ▪ Use of equipment and vehicles during construction and operations ▪ Potential release of hydrocarbons from the LSr Pipeline and Line 13 during operations	Adv	▪ Contamination of wetlands and aquifers caused by an accident or malfunction of the LSr Pipeline during operations ▪ Contamination of the South Saskatchewan River caused by an accident or malfunction of Line 13 ▪ Soil contamination from a rupture or leak due to pipeline failure during operations ▪ Water or soil contamination due to spills of hazardous materials during construction ▪ Rupture of, or damage to foreign lines, EPI's existing pipelines and cables during construction ▪ Effects on fish and fish habitat due to a release of drilling mud during horizontal directional drilling ▪ Fire during construction	X X X X X	X X
	Effects of the Environment on the Project	Y	▪ Slumping ▪ Flooding ▪ Wildfires ▪ Severe weather	Adv	▪ Delay of construction ▪ Affect the operations of the Project ▪ Damage to infrastructure	X X X	

Legend: Y (Yes); N (No); U (Uncertain); P (Positive); Ntl (Neutral); Adv (Adverse)

Bio-Physical; Socio-Economic; Other

9.3 Potential Adverse Environmental Effects

To address potential adverse environmental effects, the Applicants have proposed several mitigation strategies to avoid or minimize the effects of the Project, including avoidance through route selection; scheduling of activities to avoid sensitive periods; developing mitigation measures, including contingency plans, to address site-specific and general issues; inspection during construction to ensure mitigation is implemented and effective; and maintenance activities during the operation of the pipeline system. The reader is referred to the Applicants' application and supporting documentation for details on all the mitigation proposed by the Applicants. These measures have provided the Board with a sufficient basis to assess the potential adverse environmental effects associated with the Project and meet the objective of mitigating potential adverse environmental effects.

As noted in Section 8.0 of this Report, the analysis of potential adverse effects has been categorized into two streams: Section 9.3.1- Analysis of Potential Adverse Environmental Effects to be Mitigated through Standard Measures, and Section 9.3.2 - Detailed Analysis of Potential Environmental Effects. Note that the "Views of the Board" are provided for each of the environmental effects discussed in Section 9.3.2; whereas, the Views presented in Section 9.3.1 encompass the remaining potential adverse environmental effects identified in Section 9.2. Both sections identify recommendations in the event that regulatory approval is granted for the Project.

Field Surveys

In its application, EPI noted that a number of field surveys would be undertaken in 2007. Subsequently, EPI informed the Board that some of these surveys could not be completed until 2008, including several that would be conducted close to the start of construction.

EPI stated that for any survey reports that are submitted to the NEB after the filing of its Environmental Protection Plan (EPP) which is discussed in Section 9.4, it has mechanisms in place to ensure that updated information from these surveys would be communicated to the appropriate staff in the field. EPI also stated that federal and provincial agencies would be consulted regarding mitigation for any discoveries made during any of the environmental surveys.

EPI stated that while some biophysical field survey reports would be submitted by mid-July, late summer rare plant survey results would not be available until early August. In some instances EPI has requested permission to commence construction as soon as 10 days subsequent to the filing of the site-specific survey reports. EPI stated that it would submit the results of these outstanding studies to the NEB prior to the commencement of the LSr Pipeline construction for these site specific areas.

> *Views of the Board*
>
> The Board notes that it would be more effective if mitigation measures from the surveys were encompassed in one complete EPP as opposed to having a number of supplementary attachments. The Board also notes that completion and submission of field

surveys 10 days prior to construction is not optimal and could affect the quality of the surveys and mitigation strategies due to time constraints. The Board further notes that while EPI intends to undertake and submit a number of biophysical surveys by mid-summer of 2008, it is possible that due to weather or unforeseen circumstances, the surveys may be delayed thereby increasing the number of surveys being submitted 10 days prior to construction in those surveyed areas.

The Board acknowledges that although EPI's contingency plans filed in the application would likely result in effective mitigation for any species discovered, site-specific mitigation would not be known until surveys are completed.

To ensure that appropriate mitigation strategies would be in place and effectively communicated, upon receipt of any survey reports after the filing of the EPP, it is recommended that, as appropriate, meetings with EPI and Board staff take place prior to the commencement of construction within these site-specific areas to discuss its survey findings, proposed mitigative measures and the results of its consultations with other agencies. In its comments on the ESR, EC stated that it concurs with the Board's position that the results of the surveys must be evaluated, and mitigation strategies committed, prior to the commencement of construction.

9.3.1 Analysis of Potential Adverse Environmental Effects to be Mitigated through Standard Measures

9.3.1.1 Analysis

The Applicants have identified standard design and mitigation measures for all the potential environmental effects that were categorized in Section 9.2 as fitting into this analysis stream.

The following table provides discussion on the potential adverse environmental effects and associated standard mitigation that have been the subject of comments received by the NEB, for which the NEB required further information from the Applicants, or which involve the Applicants' commitments to other federal and provincial departments or agencies.

Potential Adverse Environmental Effect	**Notes**
Discovery of existing contaminated soils	▪ EPI has an existing 'Contaminated Soil Management Procedure' in place which addresses: o contamination identification; o initial response (*e.g.,* notification of company and government contacts); o soil handling and temporary storage; o erosion control; o soil sampling and testing; o disposal; and o documentation. ▪ EPI committed to remove and replace contaminated soils encountered during construction with clean soil, in a manner that meets or exceeds the applicable regulatory criteria.
Introduction/spreading of Weeds on LSr Pipeline RoW	▪ Leafy spurge is the primary weed of concern by the public, including government agencies. ▪ EPI stated that weeds of management concern according to the *Manitoba Weeds of Concern Act* and *Weeds of Concern Regulation* were reviewed prior to field reconnaissance. ▪ EPI has committed to undertake a weed survey prior to construction and, as outlined in Section 9.3.1.2, the Board recommends that EPI undertake a five-year post-construction monitoring program to monitor various environmental issues including weeds. ▪ EPI stated that any problematic areas noted during the post-construction monitoring program period would be controlled (e.g., hand picking, mowing or spraying), as deemed appropriate by EPI, the municipal agricultural weed specialist and landowners. ▪ Pursuant to Schedule 4 of the Manitoba Pipeline Landowners Association/ Saskatchewan Association of Pipeline Landowners (MPLA/SAPL) – EPI agreement which is explained in more detail in Section 9.3.2, EPI has committed to an additional weed management plan which applies to MPLA/SAPL members' lands affected by the Project.

Potential Adverse Environmental Effect	Notes
Fish mortality and the disturbance or alteration of fish habitat	▪ EPI has identified: o the locations of crossings; o species that are or could be present; o vehicle and pipeline crossing techniques; and o mitigation measures. ▪ EPI has undertaken 2007 fish surveys and has committed to undertaking further fish surveys in 2008, all of which would be submitted in a report to the NEB, DFO and MC. ▪ EPI stated that it is maintaining ongoing consultations with DFO and MWS regarding: Operational Statements; horizontal directional drilling crossings and DFO authorizations and potential for compensation in the event of a harmful alteration, disruption or destruction of fish habitat; and a final list of proposed watercourse crossings. ▪ EPI stated that it would adhere to all approvals, permits and authorizations issued by regulatory authorities and that any alternatives or alterations to crossing requirements specified in approvals, permits and authorizations must be approved prior to the commencement of crossing construction.
Alteration of wetlands (habitat, hydrologic and/or water quality function)	▪ EPI stated that it is developing a Wetland Characterization and Wetland Compensation Proposal to address temporary loss of wetland function arising from construction of the LSr Pipeline. Upon completion, EPI plans to provide copies of the proposal to EC and applicable provincial agencies for their review. When finalized, the goal is to have one plan in place to address wetland compensation for temporary loss of wetland function that would satisfy all parties. ▪ EPI stated that it will form a joint EPI/EC committee to address post-construction monitoring program of wetlands. In its comments on the ESR, EC stated that it is satisfied with the current ongoing process with EPI to redress permanent and temporary loss of wetland function.
Sensory disturbance and/or mortality of wildlife	▪ The Applicants stated that it would respect setback distances and timing restrictions other than in circumstances where it has listed criteria to compensate for not meeting those restrictions and would consult with appropriate agencies as required.

Potential Adverse Environmental Effect	Notes
Disturbance, alteration of habitat and /or mortality or destruction to species at risk (wildlife, fish and/or vegetation)	▪ EPI has submitted 2007 surveys and will be submitting 2008 field surveys to appropriate agencies, including a bi-valve study of the Souris River. Although the maple leaf mussel is not yet added to Schedule 1 of SARA, EPI would verify the presence of this species in the Souris River. ▪ EPI stated that EC is satisfied with the survey protocol regarding the appropriateness of the wildlife and rare plant survey methodology in relation to length of native vegetation and pasture. ▪ EPI anticipates that any discoveries made in the 2008 surveys would be similar to those found in prior surveys; however, in the event of a new discovery, EPI has committed to consult with appropriate federal and provincial agencies to confirm the suitability of proposed mitigation associated with the new discovery. ▪ EPI has "species of concern discovery contingency plans" for fish and bivalves, plants and wildlife. ▪ EPI stated that any additional information gathered from surveys, including identifying gaps that would be covered by future field surveys, would be incorporated into one document for use by key environmental construction field personnel. ▪ EPI stated that there is a program mechanism in place so that any information from field surveys undertaken 10 days prior to construction will be conveyed to the key personnel.
Alteration/disturbance of native prairie	▪ Full trench and work lane stripping would occur for the majority of the RoW that goes through native prairie to avoid the high potential for rutting and pulverization of the topsoil/sod. ▪ For localized areas where the construction RoW would be inaccessible to traffic by rubber-tired vehicles and where no grading is required, stripping would be reduced to blade width. ▪ EPI would ensure lands with native vegetation are seeded with native seed mix. ▪ EPI would avoid the use of highly invasive species on adjacent non-native prairie lands. ▪ EPI's reclamation efforts would include reducing the total area of disturbance and returning the RoW to as-near pre-construction conditions as feasible within a practical time frame.
Disturbance to agricultural and ranching operations	▪ EPI would provide notification to farmers and compensation for crop loss. ▪ In addition, post-construction monitoring may address some of these issues (refer to the Post-construction Monitoring Section 9.3.1.2 following this table).
Loss of enjoyment of property or human health effects caused by noise	▪ EPI would ensure compliance with ERCB Directive 038: Noise Control at all of the pump facilities. ▪ ERCB Directive 038: Noise Control is designed to maintain acceptable noise levels and to maintain quality of life for residents near energy industry facilities.

Potential Adverse Environmental Effect	Notes
Disturbance/destruction of heritage resources	▪ Should any previously unidentified heritage resources sites be encountered during construction of the Project, activity at that site would be stopped and the Heritage Resource Discovery Contingency Plan would be implemented. The site would be fully documented prior to resumption of construction activity. ▪ In addition to this standard mitigation, the Board recommends that EPI file with the Board the results of its archaeological and paleontological investigations and include the recommendations resulting from the archaeological and paleontological investigations, including those related to the Thornhill Burial Mounds. Further, the Board recommends that EPI: immediately cease work at the location of the discovery of any previously unidentified archaeological or heritage resources; notify responsible provincial authorities; and resume work only after approval is granted by the responsible provincial authority. (See recommendations 1 and 2 in Section 9.7 of this ESR.)
Loss or alteration of traditional sites	▪ EPI has indicated that its contingency plan, in the event that any Aboriginal interests were identified in the Project area, would consist of meeting with the Aboriginal organization or community that has identified an interest and to work with that community to jointly develop a course of action. ▪ In addition to this standard mitigation, the Board recommends that EPI file with the Board the results of the archaeological and paleontological investigations and include the recommendations resulting from the archaeological and paleontological investigations, including those related to the Thornhill Burial Mounds. Further, the Board recommends that EPI: immediately cease work at the location of the discovery of any previously unidentified archaeological or heritage resources; notify responsible provincial authorities; and resume work only after approval is granted by the responsible provincial authority. (See recommendations 1 and 2 in Section 9.7 of this ESR.)
Disruption or inability to carry on traditional activities	▪ No current traditional use of the lands along the proposed LSr Pipeline has been identified. The evidence indicates that EPI did consult with Aboriginal groups to establish whether they required traditional land and resource use studies. EPI has further indicated that its contingency plan, in the event that any Aboriginal interests were identified in the project area, would consist of meeting with the Aboriginal organization or community that has identified an interest and to work with that community to jointly develop a course of action.

Legend: Bio-Physical; Socio-Economic; Other

9.3.1.2 Post-construction Monitoring

As part of its overall mitigation, EPI has committed to undertaking a two-year post-construction monitoring program. The Board is of the view that this time frame may not be adequate to assess EPI's mitigation for a variety of environmental elements including but not limited to, soil productivity on cultivated lands, weeds, native prairie, and plant species of special concern along the LSr Pipeline. A longer monitoring time frame is required to deal with factors such as variable soil moisture conditions depending on annual climatic factors, variability of soil types encountered and variability of mitigation employed during construction. Regarding the latter, environmental effects can vary in accordance with the construction techniques or mitigative techniques employed, some of which would not be chosen until the actual time of construction. An extended time frame would also provide a more adequate data set by which to assess the efficacy of EPI's mitigation. Therefore, it is recommended the Applicants undertake a five-year post-construction monitoring program as outlined in Recommendation (3) in Section 9.7. Further, such a program should outline EPI's methodology for assessing the effectiveness of its mitigation. In their comments on the ESR, EC and MWS stated that they concur with the Board's position for a five-year post-construction monitoring program.

9.3.1.3 Views of the Board

With respect to the potential environmental effects identified in Section 9.2, other than those that are dealt with individually in the following section (9.3.2), the NEB is of the view that if the Applicants:

- effectively implement the standard design and mitigative measures proposed in the application and subsequent submissions; and
- adhere to the commitments made during the oral public hearing and the recommendations outlined in Section 9.7 of the ESR,

these potential adverse environmental effects of the Project are not likely to be significant.

9.3.2 Detailed Analysis of Potential Adverse Environmental Effects

9.3.2.1 Potential Effects on Agricultural Soils Capability

Background/Issues	EPI outlined several potential adverse effects on agricultural soil capability as indicated in Section 9.2. Any of these effects in isolation or in combination could hinder future crop growth on cultivated agricultural lands if not properly mitigated. In its evidence and Information Requests of EPI, MPLA/SAPL raised concerns regarding Project effects on agricultural soils. In particular, MPLA/SAPL submitted that: ▪ The baseline soils information being relied on by EPI was not sufficient to adequately ascertain Project effects and mitigation ▪ EPI was inappropriately using the terms "soil capability" and "soil productivity" and that the terms are neither synonymous or proxies for one another. ▪ EPI had failed to identify potential effects associated with compaction and trench subsidence. ▪ EPI's proposed mitigation was not adequate, particularly as it related to trench subsidence and compaction. ▪ EPI's proposed post-construction monitoring program was not adequate to assess Project effects on soil capability. ▪ EPI's wet soil contingency plan was not adequate as suspension of construction activities was a "last resort" after considering other contingency measures and further, the descriptors used to determine when construction should halt were too subjective. ▪ EPI had not proposed the use of a landowner construction monitor to assist in possible support of landowner concerns in resolving any soils related issues that may arise during construction. ▪ Post-construction monitoring reports from previous EPI and other pipeline construction projects that EPI was relying on as proof of the effectiveness of its proposed soil mitigation measures were based on little objective data and much subjective observation. On 19 October, 2007, MPLA/SAPL filed with the Board a Settlement Agreement

	(Agreement) that they reached with EPI and indicated that they had resolved their issues with EPI. Included within this Agreement were numerous mitigation measures that EPI committed to implement during pipeline construction within its application as well as mitigation measures specific to the Agreement. EPI also responded to questions raised by the Board throughout the proceedings pertaining to soil erosion from stockpiled soil windrows, topsoil stripping and wet weather shutdown criteria.
Mitigation Measures	Within its application and subsequent submissions, EPI outlined mitigation for alleviating potential effects on soil capability. Much of this mitigation could be considered standard mitigation that is typically employed during large diameter pipeline construction and will not be repeated here. The following is a brief summary of issues pertaining to certain mitigative strategies that were raised by either MPLA/SAPL or the Board during the course of the proceedings. *<u>Joint Committee/Independent Construction Monitor/Environmental Inspection</u>* EPI stated that it would assign a minimum of one Lead Environmental Inspector per spread while construction activities are under way and that Assistant Environmental Inspectors would be assigned as necessary during key construction activities such as clearing, topsoil stripping, water crossing construction, and topsoil replacement and erosion control during rough clean up. Resource Specialists would also be employed as required during construction at certain environmentally sensitive areas. Pursuant to the Agreement, any issues relating to potential effects on soil productivity would also likely be addressed though the Independent Construction Monitor and the Joint Committee as outlined in the Agreement. For landowners not part of MPLA, EPI committed to looking at having non-MPLA/SAPL landowners represented on the Joint Committee as well. EPI further stated that any issues or concerns raised by non-MPLA/SAPL landowners would be addressed on a per person basis as EPI is made aware of any comments or concerns that those landowners may have. *<u>Baseline Soils Information</u>* EPI submitted that its soils surveys were adequate to characterize the soils which would be encountered along the proposed pipeline route as soil surveys provide an indication as to factors such as soil types and depths but there can still be substantial variability of these factors between data points. Localized effects related to previous pipeline construction or to natural variability would be at a scale too small to map and would be addressed on site by the Environmental Inspector. Further, EPI stated that post-construction monitoring for previous EPI projects along the proposed route did not indicate any extensive topsoil/subsoil mixing issues and therefore, additional soil surveys were not warranted along the segments of the proposed pipeline route that parallel the existing EPI pipeline corridor. *<u>Compaction and Trench Subsidence</u>* According to EPI, once compacted areas have been determined through a comparison of compaction levels on and off RoW, measures for alleviating compaction included but are not limited to ripping with a multishank ripper, employing a subsoiler plow, and general cultivation across the RoW. Backfill and compaction procedures would be developed during detailed engineering but EPI stated that it would undertake baseline bulk density testing off RoW prior to backfilling of the trench. The backfilled trench would be compacted to the extent feasible, using suitable equipment along the trenchline during non-frozen conditions. Alternative methods of compaction would be used if approved by EPI's engineer. Pursuant to the Agreement, EPI further committed to subgrade surface bulk density testing on the RoW prior to ditching and after backfilling with a view to restore the RoW ditchline to within 10% of the original subgrade surface baseline measurement. EPI committed to further subsidence mitigation such as regrading, restripping, and importation of topsoil, if necessary.

	Wet/Thawed Soils Contingency Plan EPI's wet/thawed soils contingency plan provides guidance as to when certain pipeline construction activities should be suspended due to wet or thawed soils. One concern that the Board noted with the plan was that there was a potential conflict between it and EPI's proposed criteria for progressively increased topsoil stripping widths found elsewhere in its application. It was not clear if EPI intended to undertake topsoil stripping operations even during excessively wet soil conditions. In its response to Board IR 1.24, EPI clarified that topsoil salvage operations would be suspended during excessively wet soil conditions. Pursuant to the Agreement, EPI has committed to three additional provisions to the wet/thawed soils contingency plan on MPLA and SAPL member lands: ▪ consideration of a plasticity of surface soil depth indicator; ▪ implementation of contingency measures prior to the occurrence of wet/thawed soils indicators if weather conditions are such that excessively wet/thawed soil conditions are likely to occur and ▪ all heavy traffic is to be suspended in excessively wet/thawed soil conditions where topsoil has been replaced. Further, according to the Agreement, the independent construction monitor would have input into the decision as to when to suspend activities in conjunction with EPI's Chief Inspector and Environmental Inspector.
Monitoring	EPI committed to undertaking a two year post-construction monitoring program to address and resolve any issues along the LSr Pipeline RoW.

Legend: Bio-Physical; Socio-Economic; Other

Views of the Board

The Board notes the MPLA/SAPL contention that the terms soil productivity and soil capability have been used inappropriately by EPI. It is recognized by the Board that there may be uncertainty associated with these terms and they may have different uses in different contexts. However, in previous post-construction assessments, the Board has accepted the use of soil productivity as an indicator of soil capability which is often measured in terms of equivalent crop growth. Additionally, EPI has outlined its proposed post-construction monitoring program for Project effects on soils in its Application and it stated that it would undertake more detailed soil assessments as required.

Within its application and supporting evidence, EPI stated its proposed measures, including contingency plans and its environmental inspection program, for mitigating Project effects on agricultural soils. The Board notes that it will discuss with EPI any outstanding issues that it may have regarding the EPP referred to in Section 9.4.

The Board does have concerns regarding EPI's proposed two year time frame for post-construction monitoring and is of the view that two years may not be an adequate time frame for assessing the effectiveness of EPI's mitigation for Project effects on soils. Should the Project be approved, the Board recommends that EPI be required to undertake such monitoring for a period of five years (Recommendation 3). Further, the Board would assess EPI's post-construction monitoring methodology and would discuss any outstanding issues with EPI. The Board is of the view that this monitoring program would be a valuable tool for assessing the potential effects of the Project on soil capability and the success of the mitigation applied.

Overall, the Board is satisfied with EPI's proposed mitigation for Project effects on agricultural soils capability and when considered with the Board's Recommendation 3, is of the view that the Project is not likely to cause significant adverse effects on agricultural soils. This conclusion pertains to soils on the lands of both MPLA/SAPL members and non-MPLA/SAPL members due to the sufficiency of mitigation proposed for each group of landowner members.

Evaluation of Significance

Frequency	Duration	Reversibility	Geographical Extent	Magnitude
Isolated	Short-term	Short to long term	Footprint	Low to medium
Adverse Effect				
Not likely to be significant				

Refer to Appendix 4 for definitions of the Evaluation of Significance Criteria

9.3.2.2 Potential Contamination of Wetlands and Aquifers Caused by an Accident or Malfunction of the LSr Pipeline During Operations

Background/Issues	The proposed LSr Pipeline would cross a number of wetlands and run over a number of aquifers. Concerns were raised by the public, including EC, with respect to the potential water contamination, including drinking water wells, in the event of a rupture or leak during the operational phase of the Project. Areas of primary concern to EC are the Oak Lake/Plum Lake complex, the Glenboro Marsh/Black Slough and the wetland basin at KP 1161. EC recommends the installation of isolation valves on the LSr Pipeline in the above-mentioned locations. EPI assessed the need for a specialized integrity assessment program (SIAP) that would encompass the design, construction and operation phases of the pipeline segments near the Oak Lake, Assiniboine and Winkler aquifers as well as the aquifer near the Swan Lake Indian Reserve No. 7. Upon questioning from the Board, EPI stated that the SIAP would be integrated into EPI's existing integrity management program (IMP). The IMP is a requirement for Board-regulated companies under the *Onshore Pipeline Regulations, 1999* (OPR-99).
Mitigation Measures	To mitigate potential effects on aquifers, pursuant to its existing IMP and its current practices for design and construction, EPI stated that it would undertake an evaluation of the following potential mitigative strategies and select measures appropriate for the proposed LSr Pipeline Project: ▪ increase the minimum depth of cover to 1.5 m to limit the potential for third party damage ▪ increase the frequency of internal corrosion checks; ▪ optimize valve location and spacing to limit the amount of product that could be released; ▪ increase the wall thickness of the pipe; and ▪ ensure adequate cathodic protection of the pipe. EPI has committed to conducting a feasibility assessment related to the installation of isolation valves on both sides of the wetland basin at KP 1161, the Demare Slough near KP 1149, the unnamed wetland near KP 1124, the Oak Lake/Plum Lake complex and the

	Glenboro Marsh/Black Slough complex. EPI stated that the requirements for determining where isolation valves should be installed is dependent on the topography of the line and if there are sensitive areas down slope of the pipeline. EPI has a series of programs in place to minimize a potential release, to monitor the pipeline system, and to respond in the event of a release. The LSr Pipeline will be hydrostatically tested prior to operation. As required by the OPR-99, EPI has an emergency response plan (ERP) in place that was developed to be consistent with industry standard publications such as Emergency Planning for Industry (CAN/CSA-Z731). The ERP will have measures in place to promptly and effectively respond to a release of product from the LSr Pipeline. EPI has committed to update its ERP to incorporate the LSr Pipeline. EPI will develop a plan to identify alternate water supplies and commits to provide alternate water sources to affected parties, if warranted, in the event of an accidental release of product that adversely affects an aquifer.
Monitoring	Included within EPI's IMP and other operational programs are requirements for in-line inspections for denting, corrosion and cracking and other forms of monitoring the integrity of the pipeline such as regular fly overs of the RoW.

Legend: Bio-Physical; Socio-Economic; Other

Views of the Board

The Board notes that the magnitude of a rupture or leak caused from an accident or malfunction could be extensive if the product from the pipeline entered sensitive water bodies or groundwater. However, the Board is of the view that EPI's commitment to operating the LSr Pipeline in accordance with the specifications, standards and other information referred to in its application or as otherwise agreed to during the OH-3-2007 proceeding, would minimize the likelihood of a rupture or leak from occurring. Further, EPI has committed to undertaking feasibility studies for the consideration of installing isolation valves adjacent to sensitive water areas, which may help mitigate negative effects in the event of a leak or rupture.

The Board notes that it would continue to monitor EPI's pipeline and facility IMP and other operational programs to ensure that they are adequate, that they are being implemented appropriately and that they are effective.

To further minimize the likelihood of a rupture or leak and ensure public safety, the Board is of the view that, in any authorization that may be granted, EPI should be directed to:

- develop and submit a joining program that includes welding and testing procedures and manuals;
- submit a comprehensive health and safety plan and field pressure testing program; and
- construct and operate the LSr Pipeline in accordance with the information referred to in its application.

Please refer to Recommendations (4), (5) and (6) in Section 9.7 for detailed wording.

Taking into account the programs in place and the proposed recommendations, the Board is of the view that this component of the Project is not likely to cause significant adverse environmental effects as a result of accidents and malfunctions, since the likelihood of occurrence is very low.

Evaluation of Significance

Frequency	Duration	Reversibility	Geographical Extent	Magnitude
Accidental	Short-term	Short to long term	Footprint to region	High
Adverse Effect				
Not likely to be significant				

Refer to Appendix 4 for definitions of the Evaluation of Significance Criteria

9.3.2.3 Potential Contamination of the South Saskatchewan River Caused by an Accident or Malfunction of Line 13

Background/Issues	Line 13 currently handles crude oil which flows from Edmonton to the Canada/US Border. The proposed reversal would permit diluent to flow from the Canada/US Border to Edmonton. A number of concerns were raised by the public, including the Town of Outlook and the Meewasin Valley Authority, with respect to the effects of a spill or leak at the South Saskatchewan River pipeline crossing on the water supply of downstream users (*i.e.* local, Saskatoon and the Town of Outlook). EPI specified that diluent is a petroleum product. In comparison to typical crude oil, diluent disperses more readily and more is lost to evaporation upon a release. The EPI pipeline system in western Canada has for a number of years transported a variety of petroleum products including diluent products such as condensate. The toxicity and potential health effects from exposure to diluent are similar to other petroleum products transported in the EPI pipeline system.
Mitigation Measures	The Applicants stated that EPI's ERP is on file with the NEB. The ERP includes measures to prepare and respond in the event of a spill during pipeline operation. The Applicants stated that the ERP remains applicable for Line 13 operating in diluent service. The Applicants stated that EPI conducts bi-weekly aerial patrols of the pipeline system to check for any activities or situations that could affect the integrity of the pipelines (such as third party damage or bank erosion). The Applicants stated that EPI's control centre remotely monitors and controls the operation of the pipeline system using Supervisory Control and Data Acquisition systems. In the event of a pressure drop on the system indicating the possibility of a release, the operation of the pipeline can be suspended and operations personnel and equipment are deployed to the site.
Monitoring	Included within EPI's IMP and other operational programs are requirements for inline inspections for denting, corrosion and cracking and other forms of monitoring the integrity of the pipeline such as regular fly overs of the RoW.

Legend: Bio-Physical; Socio-Economic; Other

Views of the Board

As required by OPR-99, EPI has an ERP in place for the existing Line 13 crude oil service. The Board is of the view that the existing measures and monitoring undertaken by EPI would continue to be applicable during the operations for diluent service.

To further ensure public safety and minimize the likelihood of a rupture or leak at the South Saskatchewan River Crossing as well as elsewhere along the line, the Board is of the view that, in any authorization that may be granted, the Applicants be directed to:

- develop and submit a joining program that includes welding and testing procedures and manuals;
- operate Line 13 in accordance with the information referred to in its application;
- prior to placing Line 13 into diluent service, provide an engineering assessment in accordance with the Canadian Standards Association Z662-07, *Oil and Gas Pipeline Systems* which evaluates the pipeline's fitness for purpose, for the proposed reversal of flow;
- in the event that the Board is not satisfied that the engineering assessment demonstrates that Line 13 may safely commence operation in diluent service, ESL may be required to hydrotest all, or portions of Line 13; and
- after placing Line 13 into diluent service, ESL shall submit to the Board a revised engineering assessment to account for actual operating pressure profiles and pressure cycle data gathered since the reversal of flow.

Please refer to Recommendations (4), (6), (7), (8), and (9) in Section 9.7 for detailed wording.

Taking into account the programs in place and the proposed recommendations, the Board is of the view that this component of the Project is not likely to cause significant adverse environmental effects, as a result of accidents and malfunctions since the likelihood of occurrence is very low.

However, the Board recognizes concerns have been expressed about potential contamination of the water supply to downstream users, particularly to the City of Saskatoon and Town of Outlook. The Board is of the view that these concerns could be alleviated to a large extent if EPI could demonstrate that its emergency response measures will address potential contamination concerns. Therefore the Board is of the view that an emergency exercise should be undertaken for a potential rupture/leak at the South Saskatchewan River crossing to assess the effectiveness of the ERP to protect downstream water users.

Therefore, in any Order that the Board may issue, the Applicants would be directed to undertake an ERP exercise at the South Saskatchewan River Crossing. Please refer to Recommendation (10) in Section 9.7 for detailed wording.

Evaluation of Significance

Frequency	Duration	Reversibility	Geographical Extent	Magnitude
Accidental	Short-term	Short to long term	Footprint to region	High
Adverse Effect				
Not likely to be significant				

Refer to Appendix 4 for definitions of the Evaluation of Significance Criteria

9.4 Inspection

EPI stated that Environmental Inspectors would be assigned to the construction of the LSr Pipeline to ensure that proposed mitigative measures are properly implemented. In addition, EPI stated that appropriate Resource Specialists would be available onsite, when warranted, and would have expertise in the particular issues associated with the spread (*i.e.*, soil scientist, geotechnical engineer, wetland specialist, fisheries biologist, botanist, wildlife biologist, archaeologist, reclamation specialist, *etc.*). Overall, EPI committed to have a suitable number of Environmental Inspectors to provide an appropriate level of inspection. EPI further stated that training programs would be developed for all construction and inspection personnel to ensure that all individuals are aware of the environmental issues and their respective responsibilities.

During the course of the proceedings, the Board raised concerns that inspectors may have difficulty in performing their duties if they have to refer to a number of documents (*i.e.* application, supplementary submissions and manuals) to find mitigation commitments. Therefore, the NEB recommends that EPI consolidate all mitigation measures and commitments into an Environmental Protection Plan (EPP). Refer to Recommendation 11 in Section 9.7 for more details.

The Board also notes that pursuant to the NEB Act, the Board has its own inspection program and Board Environmental Inspectors are tasked with ensuring protection of property and the environment.

9.5 Cumulative Effects Assessment

The Applicants' cumulative effects assessment evaluated the adverse residual effects directly associated with the Project in combination with the adverse residual effects arising from other projects and activities that have been or will be carried out in the vicinity of the Southern Lights Project. The reader is referred to the Applicants' application for additional details on its cumulative effects assessment methodology.

9.5.1 Other Projects Interacting with the Southern Lights Project

Past, existing, and proposed projects or activities within and adjacent to the proposed corridor include, but are not limited to, oil and gas activity, roads, rail lines, agriculture, power lines, and wind generation projects. The predominant projects that the Applicants noted which could potentially interact with the Southern Lights Project include:

- existing EPI pipelines within the RoW that the LSr Pipeline would parallel;
- EPI's proposed Alberta Clipper Project that would parallel the LSr Pipeline route with a five-metre separation;
- EPI's proposed Southern Access Project;
- TransCanada Keystone's proposed oil pipeline where it crosses the LSr Pipeline route; and
- proposed wind generation projects in the vicinity of the LSr Pipeline route.

EPI's existing pipelines and its proposed Alberta Clipper Project are the projects most likely to result in direct cumulative environmental effects with the Southern Lights Project. The LSr Pipeline route would follow the same route as the Alberta Clipper pipeline from the Cromer Terminal to the Canada/US border.

9.5.2 Potential Cumulative Effects

The Applicants identified potential cumulative residual effects associated with the following elements:

- physical elements such as slope stability, soils, water quality and quantity, air quality including greenhouse gases, and acoustic environment;
- biological elements such as fish and fish habitat, wetlands, vegetation, wildlife and wildlife habitat, and species at risk;
- socio-economic elements such as human occupancy and resource use, heritage resources, traditional land and resource use, human health and infrastructure and services; and
- accidents and malfunctions.

The Applicants stated that its proposed Project-specific environmental protection and mitigative measures are sufficient to address potential cumulative effects and that the cumulative residual environmental and socio-economic effects associated with the construction and operation of the Project are not unlike those routinely encountered during pipeline and associated facility construction in an agricultural setting. However, as discussed in the following paragraphs, the Applicants also proposed to undertake specific mitigative measures to address cumulative effects related to certain bio-physical and socio-economic elements.

Soil Capability

The Applicants stated that the LSr Pipeline component of the Southern Lights Project would act cumulatively with previous disturbances and the Alberta Clipper Project in that an incremental change in soil capability would occur. Past activities which have affected soil capability are largely attributed to agricultural activities and previous pipeline construction programs. In addition, since the Alberta Clipper Project and the LSr Pipeline would share the same construction RoW, residual effects on soil arising from Alberta Clipper would be expected to act cumulatively with the LSr Pipeline. The Applicants noted that to a lesser extent, the LSr Pipeline may also act cumulatively with the residual effects arising from the construction of the Keystone Pipeline Project but such effects would be limited to the segment where the LSr Pipeline and the Keystone pipeline intersect.

In its original application, the Applicants proposed construction of both the Southern Lights and Alberta Clipper projects to commence in late 2007 and extend until 2009.

In August 2007, the Applicants submitted a revised cumulative effects assessment considering the scenario that construction of the pipeline component of the Alberta Clipper Project from Cromer to the Canada/US border would be undertaken one year after construction of the LSr Pipeline component of the Southern Lights Project. The former would generally commence in summer 2009 and the latter in summer 2008.

If constructed on their own, the LSr and Alberta Clipper pipelines would be constructed with a 5 m separation and each would require a 40 m wide construction RoW. However, since the two projects would parallel one another and be constructed within a year of each other, the rights-of-way and temporary workspace would be shared and overlapping. Thus, the total construction RoW width for both pipelines would be 45 m.

To minimize topsoil handling and therefore reduce the potential of topsoil and subsoil mixing, the Applicants proposed to leave the topsoil in rows along the RoW in between the two periods of construction to avoid disturbing the topsoil twice. Measures would be taken to stabilize the topsoil and prevent wind erosion and weed infestation. However, the Applicants also stated that if it was the landowner’s preference, it would replace the topsoil at the end of the first construction season and that in either case, landowners would be compensated appropriately. Final clean-up and reclamation of the combined construction RoW would generally be conducted in the late fall 2009.

The Applicants further noted that its proposed soil handling methods would also result in overall decreased disturbance, which in turn would result in reduced effects on other elements such as wildlife and vegetation and decrease the potential for the spreading of weeds.

Other Biophysical and Socio-Economic Elements

The Applicants also proposed to install the LSr and Alberta Clipper pipelines simultaneously during construction of the LSr Pipeline component of the Southern Lights Project at certain locations in order to minimize disturbance. These locations include several potentially sensitive watercourse crossings, the Glenboro Marsh / Black Slough wetland complex (KP 1106.9 to KP 1114.5), and within the town of Morden (KP 1195.9 to KP 1197). The Applicants submitted that co-construction of the pipelines through these areas would likely result in reduced cumulative adverse effects on water quality and quantity, fish and fish habitat, wetlands, vegetation and wildlife, including species at risk, and other land uses in the Morden area.

9.5.3 Applicants’ Conclusion

The Applicants submitted that with the implementation of its proposed mitigative strategies, the potential cumulative adverse residual effects associated with the construction and operation of the Project on biophysical and socio-economic elements would not be likely to be significant.

9.5.4 Views of the Board

The Applicants proposed concurrent construction of the Alberta Clipper and Southern Lights projects at certain locations is likely to result in reduced environmental effects on water quality and quantity, fish and fish habitat, wetlands, vegetation and wildlife, including species at risk, and other land uses in the Morden area. Further, the Applicants soil handling plans to accommodate both projects would lessen potential adverse effects on soil capability. Co-construction of the projects would result in less overall temporal and spatial disturbance on these environmental elements and is the preferred approach should both projects be approved. However, the Board is also of the view that the Applicants' proposed project-specific environmental protection and mitigation measures are sufficient such that cumulative adverse environmental effects resulting from the projects are not likely to be significant in the event that stripping and topsoil replacement or co-construction of the pipes cannot occur at the same time.

The Board is of the view that, taking into consideration the Applicants' proposed Project-specific mitigation measures, its additional measures proposed to further mitigate cumulative effects, and the recommendations referred to in Section 9. 7, the Project would not likely result in significant adverse cumulative environmental effects in combination with other projects or activities that have been or will be carried out.

9.6 Follow-Up Program

The Project and its associated activities are generally routine in nature and the potential adverse environmental effects of the Project are expected to be similar to those of past projects of a similar nature in a similar environment. For this reason, the NEB is of the view that a follow-up program pursuant to the CEA Act would not be appropriate for this Project.

However, it is recommended that the Applicants undertake detailed post-construction monitoring as discussed in sections 9.3.1.2 and 9.3.2.

9.7 Recommendations

It is recommended that, in any authorization that the NEB may grant, a condition be included requiring the Applicants to carry out all of the environmental protection and mitigation measures outlined in its application and subsequent submissions.

Further, other recommendations include:

(1) EPI shall:

(a) file with the Board, at least 60 days prior to the commencement of construction, the results of the archaeological and paleontological investigations; and

(b) include the recommendations resulting from the archaeological and paleontological investigations, including those for the Thornhill Burial Mounds, in the EPP.

If appropriate, EPI may file the results related to the LSr Station Facilities and the LSr Pipeline excluding the LSr Station Facilities separately. If filed separately, the results for the LSr Station Facilities must be filed at least 60 days prior to the commencement of construction of those facilities. The results for the LSr Pipeline excluding the LSr Station Facilities must be filed at least 60 days prior to the commencement of the construction of the LSr Pipeline excluding the LSr Station Facilities.

(2) EPI shall, in the event that previously unidentified archaeological or heritage resources are discovered:

(a) immediately cease work at the location of the discovery and notify responsible provincial authorities; and

(b) resume work only after approval is granted by the responsible provincial authority.

(3) On or before the 31 of January of each of the first 5 years following the commencement of the operation of the LSr Pipeline, EPI shall file with the Board, and make available on its website for informational purposes, a post-construction environmental report that:

(a) identifies on a map or diagram the location of any environmental issues which arose during construction;

(b) discusses the effectiveness of the mitigation applied during construction and the methodology used to assess the effectiveness of mitigation;

(c) identifies the current status of the issues identified (including those raised by landowners), and whether those issues are resolved or unresolved; and

(d) provides proposed measures and timelines EPI shall implement to address any unresolved concerns.

The report shall address, but not be limited to, issues pertaining to soil productivity on cultivated lands, weeds, reclamation of native prairie, water course crossings, and plant species of special concern.

(4) EPI shall develop joining programs for: the LSr Pipeline (excluding the LSr Station Facilities); the LSr Station Facilities; and Line 2. ESL shall develop the joining program for Line 13 Reversal. Both shall file these with the Board at least 60 days prior to commencement of any welding activities to which the programs relate. The joining programs shall include:

(a) requirements for the qualification of welders;

(b) requirements for the qualification and duties of welding inspectors;

(c) the welding techniques and processes EPI/ESL would be using;

(d) the welding procedure specifications and procedure qualification records;

(e) the welding procedure specifications for welding on in-service pipelines (where applicable);

(f) the non-destructive examination (NDE) procedures, and supporting procedure qualification records, which detail the ultrasonic and/or radiographic techniques and processes EPI/ESL would be using, for each welding technique;

(g) the defect acceptance criteria for each type of weld (i.e. production, tie-in and repair);

(h) an explanation of how the defect acceptance criteria were determined; and

(i) any additional information which supports the joining program.

(5) EPI shall file with the Board the following programs and manuals within the time specified:

(a) comprehensive health and safety plan related to the LSr Station Facilities – at least 60 days prior to construction of the LSr Station Facilities;

(b) comprehensive health and safety plan related to the LSr Pipeline excluding the LSr Station Facilities – at least 60 days prior to construction of the LSr Pipeline excluding the LSr Station Facilities; and

(c) field pressure testing program for the LSr Pipeline – at least 14 days prior to pressure test.

(6) EPI shall cause the approved Project to be designed, located, constructed, installed, and operated in accordance with the specifications, standards and other information referred to in its application or as otherwise agreed to during the OH-3-2007 proceeding.

(7) ESL shall file with the Board for approval, at least 9 months prior to placing Line 13 into diluent service, an engineering assessment (EA) in accordance with the Canadian Standards Association Z662-07, *Oil and Gas Pipeline Systems* which evaluates the pipeline's fitness for purpose, for the proposed reversal of flow. The EA shall account for, but not be limited to:

(a) a comparison of excavation findings with associated results from all crack in-line inspections (ILI) performed during current service, and with associated results from the most recent geometry ILIs;

(b) a confirmation of the accuracy of the ILI tools, or measures undertaken to mitigate potential inaccuracies;

(c) the pipeline condition after completion of repairs, including type and dimensions of remaining crack and geometry features;

(d) a comparison of operation prior to reversal versus future service conditions, including cyclical loading estimates;

(e) the estimated defect growth and time until failure, once Line 13 is reversed;

(f) pipe design and material properties (such as toughness) of the various Line 13 portions;

(g) transient analyses completed on Line 13;

(h) consequences of failure, with regard to pipe properties described in (f); and

(i) other potential hazards that may be aggravated by the proposed reversal of Line 13.

(8) In the event that the Board is not satisfied that the engineering assessment demonstrates that Line 13 may safely commence operation in diluent service, ESL shall be required to hydrotest all, or portions of Line 13. If hydrotesting is required, ESL shall file with the Board for approval its Pressure Testing Program at least four weeks prior to the commencement of pressure testing activities.

(9) No later than 6 months after placing Line 13 into diluent service, ESL shall submit to the Board a revised engineering assessment to account for actual operating pressure profiles and pressure cycle data gathered since the reversal of flow. As part of ESL's engineering assessment, estimated defect growth rates and in-line inspection intervals shall be adjusted accordingly.

(10) Within 6 months after commencement of operation of Line 13 in diluent service:

(a) ESL shall conduct an emergency response exercise at its South Saskatchewan River crossing and relevant downstream control points with the objectives of testing:

- emergency response procedures, including response times;
- training of company personnel;
- communications systems;
- response equipment;
- safety procedures; and
- effectiveness of its liaison and continuing education programs.

(b) ESL shall notify the Board, at least 30 days prior to the date of the emergency response exercise, of the following:

- the date(s) and location(s) of the exercise;
- the type of exercise;
- the exercise scenario;
- the proposed participants in the exercise;
- the objectives of the exercise; and
- the evaluation criteria.

(c) ESL shall file with the Board, within 60 days after the emergency response exercise outlined in (a), a final report on the exercise including:

- the results;
- how objectives were achieved;
- areas for improvement; and

- steps to be taken to correct deficiencies.

(11) EPI shall file with the Board for approval, at least 60 days prior to construction, an updated project-specific Environmental Protection Plan (EPP). The EPP shall describe all environmental protection procedures, and mitigation and monitoring commitments, as set out in EPI's application or as otherwise agreed to during questioning, in its related submissions or through consultations with other government agencies. Construction shall not commence until EPI has received approval of its EPP from the Board. If appropriate, the Applicants may submit two separate EPPs, one for the LSr Pipeline excluding the LSr Station Facilities and the other for the LSr Station Facilities.

10.0 THE NEB'S CONCLUSION

The NEB is of the view that with the implementation of the Applicants' environmental protection procedures and mitigation measures and the NEB's recommendations, the proposed Project is not likely to cause significant adverse environmental effects.

This ESR was approved by the NEB on the date specified on the cover page of this report under the heading CEA Act Determination Date.

11.0 NEB CONTACT

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APPENDIX 1 SCOPE OF THE ENVIRONMENTAL ASSESSMENT (AS DETERMINED IN JUNE 2007)

National Energy Board Office national de l'énergie

File OF-Fac-Oil-E242-2007-01 01
6 June 2007

To: Distribution List

Enbridge Southern Lights Limited Partnership (ESL) and Enbridge Pipelines Inc. (EPI)
Proposed Southern Lights Pipeline Project
Scope of the Environmental Assessment Pursuant to the
Canadian Environmental Assessment Act

On 27 April 2007, the National Energy Board (the Board) requested comments from the public on the draft scope of environmental assessment for the proposed Southern Lights Pipeline Project.

The Board received a letter of comment from the Meewasin Valley Authority, which posed the following question in the context of the cumulative effects assessment related to the Project: "Does the phrase "other projects" include all existing pipelines that have been constructed within the right-of-way, regardless of ownership?" The Board is of the view that the phrase "other projects" in factor (a) of Section 2.2 of the Scope of the Environmental Assessment includes all existing pipelines, regardless of ownership, that may be the source of environmental effects that may potentially interact with the environmental effects of the proposed Southern Lights Pipeline Project. Therefore, the Scope, as drafted, will adequately consider the cumulative environmental effects of accidents and malfunctions that are likely to result from the Southern Lights Pipeline Project in combination with other projects or activities that have been or will be carried out.

The Board also received a letter of comment from the Roseau River Anishinabe First Nation (RRAFN). The RRAFN stated that the Southern Lights Pipeline Project adversely affects the "constitutionally protected s. 35 interests of the RRAFN" and registered its concern that appropriate consultation be carried out. The RRFAN did not, however, provide information on the specific interests adversely impacted by the proposed Project and did not suggest any changes to the draft Scope. As a result, the Board is of the view that it is not necessary to make any changes to the draft Scope based upon the comments of the RRAFN. The Board notes that the CEA Act mandates consideration of any change that the Project may cause in the environment and any impact of such a change on the current use of lands and resources for traditional purposes by Aboriginal peoples. It also requires the consideration of mitigation measures proposed to minimize any such impact. These requirements have been incorporated into the Scope. Furthermore, the impacts of the Project on Aboriginal peoples is also a specific issue in the public hearing process that has been established in respect of the Project.

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Accordingly, in response to the comments received, the Board has not made any changes to the draft Scope. The Board also notes that the Board, Transport Canada and Indian and Northern Affairs Canada are responsible authorities (RAs) pursuant to the *Canadian Environmental Assessment Act* for the proposed Project and the RAs have determined the scope of the environmental assessment, as attached to this letter.

The Board notes that the RRFAN has been forwarded a copy of the Hearing Order issued in relation to the Southern Lights Pipeline Project, which outlines in detail the various means of participating in the NEB proceeding.

Yours truly,

David Young
Acting Secretary

Enbridge Southern Lights Limited Partnership and
Enbridge Pipelines Inc.
Proposed Southern Lights Pipeline Project
Scope of the Environmental Assessment Pursuant to the
Canadian Environmental Assessment Act

1.0 INTRODUCTION

Enbridge Southern Lights Limited Partnership (ESL) and Enbridge Pipelines Inc. (EPI) are proposing to construct and operate the Southern Lights Pipeline Project (the Project). A Certificate of Public Convenience and Necessity pursuant to section 52 and Orders pursuant to section 58 of the *National Energy Board Act* (NEB Act) to construct and operate the proposed Project would be required and the project would be subject to an environmental screening under the *Canadian Environmental Assessment Act* (CEA Act).

On 14 November 2006, Enbridge filed a Preliminary Information Package with the Board regarding the proposed Project. The intent of the Preliminary Information Package was to initiate the environmental assessment (EA) process pursuant to the CEA Act. The following departments subsequently identified themselves as having responsibilities or an interest under the CEA Act in the EA of the proposed Southern Lights Pipeline Project:

- National Energy Board – required to conduct an EA under the CEA Act (Responsible Authority (RA))
- Transport Canada, Navigable Waters – RA
- Indian and Northern Affairs Canada – RA
- Environment Canada – in possession of specialist or expert information or knowledge (Federal Authority (FA))
- Health Canada - FA
- Department of Fisheries and Oceans – FA
- Natural Resources Canada - FA

The Provinces of Manitoba and Saskatchewan also expressed an interest in monitoring and participating in the EA coordination process although Provincial EA legislation is not triggered.

The Canadian portion of the Project would consist of three components. The Project would include conversion of Line 13 from crude oil service to diluent service and reversal of Line 13 to allow flow from the Canada - United States (US) border near Gretna, Manitoba (MB) to Edmonton, Alberta (AB). The Project would also involve construction of approximately 286 km of new 508 mm (NPS 20-inch outside diameter) light sour (LSr) crude oil pipeline from Cromer, MB to the Canada - US border near Gretna, MB. The Project also includes the modification of certain Line 2 pump stations and the addition of drag reducing agent (DRA) injection systems between Edmonton, AB and Canada - US border near Gretna, MB. Approximately 8 km of new right of way (RoW), not contiguous with or alongside existing RoW, would be required for the new pipeline facilities. Construction of the new pipeline facilities would require the crossing of

11 named watercourses, including the Souris and Cypress Rivers. There may also be other related physical works and activities associated with the Project.

The scope of the EA was established in accordance with the CEA Act and the CEA Act *Regulations Respecting the Coordination by Federal Authorities of Environmental Assessment Procedures and Requirements* which state that the RAs shall establish the scope of the EA after consulting with FAs. The Provinces of Manitoba and Saskatchewan also reviewed the draft scope.

2.0 SCOPE OF THE ASSESSMENT

2.1 Scope of the Project

The scope of the Project as determined for the purposes of the EA includes the various components of the Project as described by ESL and EPI in their 14 November 2006 Preliminary Information Package and 9 March 2007 Application, submitted to the National Energy Board.

The scope of the Project includes construction, operation, maintenance and foreseeable changes, and where relevant, the abandonment, decommissioning and rehabilitation of sites relating to the entire Project, and specifically, the following physical works and activities:

Line 13 Reversal

- Enbridge's existing Line 13 would be reversed from the Canada – US border near Gretna, MB to Edmonton, AB to allow for a south to north flow. This reversal would allow the redeployment of Line 13 from crude oil service to diluent service. No new diluent pipeline construction would be required in Canada.
- Modifications to 17 existing pump stations on Line 13 in AB, SK and MB. Sixteen of these stations would be modified for reverse flow service and one station in Edmonton, AB would be redeployed.
- The installation of DRA skids within existing station boundaries at 4 existing line 13 pump stations.

Light Sour Crude Pipeline

Construction of approximately 286 km of a new 29,500 M^3/day (185,000 bbl/day), 508 mm (NPS 20-inch OD) light sour crude oil pipeline from Cromer, MB to the Canada - US border near Gretna, MB The construction in Canada would be in or alongside and contiguous to existing EPI right of way (RoW) for almost its entire length. Approximately 8 km of new non-contiguous RoW would be required. Three new pumping units would be required and each would be located within existing Enbridge pump station boundaries.

Line 2 Modifications

Modifications to certain of EPI's existing Line 2 pump stations between Edmonton, AB and the Canada – US border near Gretna, MB specifically:

- replacement of 17 Line 2 pumps and motors at existing pump stations.
- The addition or recommissioning of DRA skids within existing station boundaries at 22 existing Line 2 pump stations.

Related Undertakings and Activities

Staging areas, temporary construction workspace, access roads, any required work camps, and equipment laydown areas are also included in the scope of the Project.

It should be noted that any additional modifications or decommissioning/abandonment activities would be subject to future examination under the NEB Act and consequently, under the CEA Act, as appropriate. Therefore, at this time, these activities will be examined in a broad context only.

Navigable Watercourse Crossings

Additionally, for greater clarity, the Scope of the Project includes the crossings of navigable watercourses.

2.2 Factors to be Considered

The EA will include a consideration of the following factors listed in paragraphs 16(1)(a) to (d) of the CEA Act:

(a) the environmental effects of the Project, including the environmental effects of malfunctions or accidents that may occur in connection with the Project and any cumulative environmental effects that are likely to result from the Project in combination with other projects or activities that have been or will be carried out;

(b) the significance of the effects referred to in paragraph (a);

(c) comments from the public that are received during the environmental assessment process; and

(d) measures that are technically and economically feasible and that would mitigate any significant adverse environmental effects of the Project.

In addition, pursuant to paragraph 16(1)(e), the EA will consider alternative means of carrying out the Project that are technically and economically feasible and the environmental effects of any such alternative means.

For further clarity, subsection 2(1) of the CEA Act defines 'environmental effect' as:

a) any change that the project may cause in the environment, including any change that the project may cause to a listed wildlife species, its critical habitat or the residences of individuals of that species as defined in the *Species at Risk Act*;
b) any effect of any change referred to in paragraph (a) on
    i. health and socio-economic conditions,
    ii. physical and cultural heritage,
    iii. the current use of lands and resources for traditional purposes by aboriginal persons,
    iv. any structure, site or thing that is of historical, paleontological, or architectural significance; or
c) any change to the project that may be caused by the environment, whether any such change or effect occurs within or outside Canada.

2.3 Scope of Factors to be Considered

The EA will consider the potential effects of the proposed Project within spatial and temporal boundaries within which the Project may potentially interact with, and have an effect on components of the environment. These boundaries will vary with the issues and factors considered, and will include:

- construction, operation, decommissioning, site rehabilitation and abandonment or other undertakings that are proposed by the Proponent or that are likely to be carried out in relation to the physical works proposed by the Proponent, including mitigation and habitat replacement measures;
- the natural variation of a population or ecological component;
- the timing of sensitive life cycle phases of wildlife species in relation to the scheduling of the Project;
- the time required for an effect to become evident;
- the time required for a population or ecological component to recover from an effect and return to a pre-effect condition, including the estimated degree of recovery;
- the area affected by the Project; and
- the area within which a population or ecological component functions and within which a Project effect may be felt.

For the purpose of the assessment of the cumulative environmental effects, the consideration of other projects or activities that have been or will be carried out will include those for which formal plans or applications have been made.

APPENDIX 2 LOCATIONS OF PROPOSED WORK/ACTIVITIES AT EXISTING PUMP STATIONS

Pump Station	Line 2 Modifications	LSr Pipeline	Line 13 Reversal
Edmonton	■		■
Kingman	■		■
Strome	■		
Hardisty	■		■
Metiskow	■		■
Cactus Lake	■		
Kerrobert	■		■
Herschel	■		■
Milden	■		
Loreburn	■		■
Craik	■		■
Bethune	■		
Regina	■		■
White City	■		
Odessa	■		■
Glenavon	■		■
Langbank	■		■
Cromer	■	■	■
Souris	■		■
Glenboro	■	■	■
St.Leon			■
Manitou	■	■	
Gretna	■		■

APPENDIX 3 COMMENTS ON THE DRAFT ESR

Agencies	Comments	Section in ESR where wording was modified	Explanation on why change was not made to the ESR
TC	TC specified revisions to existing wording on TC's mandate and the scope of its analysis	Revisions made to Section 3.1	n/a
INAC	INAC recommended that the following information be provided: regulations governing the disposal of water-methanol; qualification and training requirements for personnel during operations; and the seasons when surveys took place. INAC also recommended that the Applicants should continue discussions with the Swan Lake First Nations regarding potential impacts on its membership.	n/a	These issues have been addressed in the draft ESR, as written, other submissions from the Applicants, or can be addressed through existing regulatory requirements.
INAC	INAC proposed wording changes to the scope of the environmental assessment	n/a	The scope of the environmental assessment was established by the RAs on 6 June 2007.
EC	EC stated that it is satisfied with the current ongoing process with EPI to redress the loss of wetland function.	This comment was added to section 9.3.1.1	n/a
EC	Regarding the submission of some field surveys 10 days prior to construction, EC stated that it concurs with the Board's position that the results of the surveys must be evaluated, and mitigation strategies committed, prior to the commencement of construction.	This comment was added to section 9.3	n/a
EC and MWS	EC and MWS stated that they concur with the Board's recommendation of a five-year post-construction monitoring program.	These comments were added to section 9.3.1.2	n/a
EC	EC stated that it preferred a reroute, or alternatively, installation of isolation valves in the vicinity of specific wetlands (i.e. Oak Lake/Plum Lake, Glenboro Marsh, KP 1161, Demare Slough and KP 1124), as the potential for oil spills in wetlands is of significant concern.	n/a	The Applicants responded to this concern by stating that they have committed to run the Intelligent Valve Placement model with consideration of the wetlands and to discuss the outcomes of the model with EC. In previous submissions, the Applicants stated that a formal risk reduction review has been completed and feasibility assessments are under review to determine the optimal valve location and spacing to reduce volume out in the event that a release occurs in high consequence areas. The Board notes that the placement of

Agencies	Comments	Section in ESR where wording was modified	Explanation on why change was not made to the ESR
			isolation valves, if any, would be based on additional engineering considerations including the Applicants' formal risk reduction review and its Intelligent Valve Placement model. The Board further notes that, through its ongoing environmental oversight during the construction and operational phases of the Project, the Board would maintain ongoing contact with the Applicants and EC to obtain their views on the location of isolations valves.
DFO	DFO recommended revised figures for the number of watercourses with potential to support spring spawning sports fish and the number of undefined drainages.	Revisions were made to Section 6.1.	
DFO	DFO recommended adding two additional project-environment interactions within the fish and fish habitat entry: (1) bank instability at the crossing sites leading to bank erosion; and (2) disruption of fish habitat at the crossing sites during isolation of the sites).	The first recommended interaction was added within Section 9.2	The second recommended interaction was not added since it is implicitly addressed through existing wording.
DFO	DFO noted that the species of special concern discovery contingency plans were not elaborated upon in Section 9.3.1 and that a "program mechanism" for conveyance of information from field surveys to key personnel was not explained. DFO also commented that crossings may take place outside frozen and dry stream crossing timeframes.	n/a	The issues have been already addressed in the draft ESR, as written, or other submissions from the Applicants; therefore, changes were not made. Further, the Board notes that EPI has stated in its submissions that it is maintaining ongoing consultations with DFO and MWS, that it would adhere to all approvals, permits and authorizations issued by regulatory authorities and that any alternatives or alterations to crossing requirements specified in approvals, permits and authorizations must be approved prior to the commencement of crossing activities.
HC	HC stated that it was unclear from the ESR as to whether any assessment was undertaken for naturally occurring radioactive materials (NORMs) for the construction and operation phases of the Project.	n/a	The Applicants stated that it considered available information and determined that NORMs are not a concern for this Project. The Board is satisfied with the Applicants assessment in this regard.
HC	HC recommended that noise from all phases of the Project be added as a potential Project-environment interaction under the Environmental Element category of "Human Health".	Revisions were made to Sections 7.2, 9.2, 9.3.1.1.	n/a

Agencies	Comments	Section in ESR where wording was modified	Explanation on why change was not made to the ESR
HC	HC recommended clarification of whether compliance with ERCB Directive 038: Noise Control also includes modified existing pumps and motors in addition to the new ones.	Revision was made to Section 5.2.	n/a
HC and MIA	HC and MIA expressed concern that the ERCB Directive 038: Noise Control appears only to have regulatory authority in Alberta and HC stated that the Directive is not applicable to construction noise. HC recommended that the Directive also be adhered to for the construction phase of the Project.		Although the Directive focuses on the operations phase of the Project, the Applicants have provided standard mitigation measures to address noise during construction. As the Applicants have committed to the Directive for the whole Project, the Applicants would be in non-compliance with their commitment if they were not meeting the guidelines of the Directive in any of the three provinces where the Project is located.
MC	MC commented on consultation with Aboriginal communities.	n/a	These comments do not alter the analysis set out in the draft ESR within Section 9.3.1.1 under the “Disruption or inability to carry on traditional activities”.
MWS	MWS recommended the inclusion of “water course crossings” as part of the post-construction environmental report.	Revision was made to Section 9.7.	n/a
MWS	MWS identified “blasting” and “hydrostatic testing” as a Project/environment interaction.	Revision was made to Section 9.2.	n/a
MWS	MWS discussed potential effects of the Project on important wetland and fisheries habitat along the proposed route. MWS also highlighted provincial permitting obligations.	n/a	The Board notes that the Applicants’ will be required to obtain any necessary provincial authorizations for the Project.
Applicants	The Applicants recommended: inserting updated information for the “Terrain and Soils” and “Wetlands” descriptions; deleting some wording within the “Disturbance to agricultural and ranching operations” entry for clarification purposes; and including the use of hot water as an alternative to water-methanol mixture for hydrostatic testing of the pipelines within the Description of the Project section.	Revisions were made to Sections 5.1, 6.1 and 9.3.1.1.	n/a

n/a - not applicable

APPENDIX 4 SIGNIFICANCE CRITERIA DEFINITIONS

The table below defines the criteria used by the NEB for evaluating the significance of the effects discussed in Section 9.3.2. These criteria and definitions are largely based on information used by the Applicants. However the NEB added its own criteria, Evaluation of Significance, and included a corresponding definition.

Criteria	Definition
Frequency (how often would the event that caused the effect occur)	**Accidental**: Occurs rarely over assessment period **Isolated**: Confined to specified period **Occasional**: Occurs intermittently and sporadically over assessment period **Periodic**: Occurs intermittently but repeatedly over the construction and operations period **Continuous**: Occurs continually over the construction and operations period
Duration (period of the event causing the effect)	**Immediate**: Event duration is limited to less than or equal to two days **Short-term**: Event duration is longer than two days but less than or equal to one year. **Medium-term**: Event duration is longer than one year but less than or equal to ten years **Long-term**: Event duration extends longer than ten years
Geographic Extent	**Footprint**: The land area disturbed by the Project, construction and reclamation activities, including associated physical works and activities (*i.e.*, permanent pipeline RoW, temporary construction workspace, temporary stockpile sites, temporary staging areas, facility sites) **Local**: The area which could potentially be affected by construction and reclamation activities beyond the construction RoW including associated physical works and activities. The local boundary varies with the discipline and issue being considered (*e.g.*, for assessment of the effects of noise on wildlife, the area affected by noise (*i.e.*, 2 km buffer) from the source is included in this boundary) **Region**: The area extending beyond the local boundary. The boundary for the region also varies with the discipline and the issue being considered (*e.g.*, for socio-economic analysis, regional boundaries include large communities that will be used as construction offices or regional municipal district boundaries) **Province**: The area extending beyond regional or administrative boundaries, but confined to Manitoba, Saskatchewan or Alberta (*e.g.*, provincial permitting boundaries, etc.) **Transboundary**: The area extending outside Canada
Reversibility	**Immediate**: Effect is alleviated in less than or equal to two days **Short-term**: Greater than two days and less than or equal to one year to reverse effect **Medium-term**: Greater than one year and less than or equal to ten years to reverse effect **Long-term**: Greater than ten years to reverse effects **Permanent**: Residual effects are irreversible
Magnitude	**Negligible**: Residual effects are not detectable **Low**: Potential effects are detectable, but well within environmental and/or social standards or tolerance **Medium**: Potential effects are detectable and approaching, but below environmental and/or regulatory standards or tolerance **High**: Potential effects are beyond environmental and/or social standards or tolerance
Evaluation of Significance	"**Likely to be significant**" would typically involve effects that are: high probability, irreversible, regional in extent and/or of high magnitude

Rating Report

Report Date:
July 6, 2012

Previous Report:
October 26, 2011

Insight beyond the rating.

Alliance Pipeline Limited Partnership

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The Company

Alliance Pipeline Limited Partnership, 50/50 owned by Enbridge Income Fund (rated BBB (high) by DBRS) and Veresen Inc. (rated BBB (high) by DBRS), owns the Canadian portion of Alliance Pipeline, which is an integrated high-pressure (up to 1,740 pounds per square inch (psi) versus the usual 1,000 psi to 1,100 psi) natural gas pipeline from northeastern British Columbia and northwestern Alberta to several delivery points in the Chicago area. It extends for 970 miles in Canada and 890 miles in the United States, with laterals providing access to 52 receipt points, primarily gas plants. Alliance currently operates under transportation contracts with shippers. The majority of the contracts expire on December 1, 2015.

Rating

Debt	Rating	Rating Action	Trend
Senior Secured Notes	A (low)	Confirmed	Stable
Senior Unsecured Notes	BBB (high)	Confirmed	Stable

Rating Update

DBRS has confirmed the Senior Secured Notes and Senior Unsecured Notes of Alliance Pipeline Limited Partnership (Alliance Canada or the Partnership) at A (low) and BBB (high), respectively, both with Stable trends. Alliance Canada is the Canadian portion of the Alliance Pipeline System (collectively, Alliance), which includes Alliance Pipeline L.P. (Alliance USA – see separate report), the U.S. portion.

The rating is based on strong and predictable cash flow from take-or-pay shipper contracts (which end December 1, 2015) to service the amortization amount of the debt and interest throughout the contact term. Shipper contacts cover 100% of Alliance's pipeline base capacity and are with strong credit profile shippers, with 89% of the shippers (the Canadian portion of the system) having investment-grade ratings. Although the renewal of new contracts beyond 2015 remains uncertain and future competition or economic conditions could force Alliance to realize lower earnings and cash flow than the current contracts (currently not expected), this risk is mitigated by: (1) the Alliance pipeline system (the System) remains relatively competitive from a cost perspective, which is expected to enhance its ability to obtain new contracts; (2) the System could run at 20% over its base capacity, which could help to generate additional cash flow; and (3) a considerable amount of debt will be retired by the end of the contracts.

Despite these strengths, Alliance Canada's financing flexibility is limited by its high debt levels. The debt-to-capital ratio remained relatively high at 68.5% at the end of Q1 2012 (64% on a senior secured debt basis), and was close to the 70% maximum senior debt leverage level allowed in the covenant. As Alliance is seeking to become a more conventional pipeline, increases in capital expenditures are expected over the medium term (particularly on the U.S. portion) and could place pressure on the balance sheet. Furthermore, earnings have been impacted by a declining investment base, as the System is depreciating over time. Although DBRS assesses the credit quality of Alliance Canada on a standalone basis, due to cross-default provisions between Alliance Canada and Alliance USA, DBRS believes that a change in credit worthiness of Alliance USA could impact the credit profile of Alliance Canada and vice versa.

Rating Considerations

Strengths
(1) Competitive toll to the Chicago area
(2) Take-or-pay shipper contracts
(3) Covenant and debt service coverage protection
(4) Good growth potential

Challenges
(1) Most shipper contracts expire in 2015
(2) Non-investment-grade shippers (11%)
(3) Cross-default provisions
(4) High leverage

Financial Information

	USGAAP	USGAAP		CGAAP	CGAAP	CGAAP	CGAAP	CGAAP
Alliance Pipeline Limited Partnership	**3 mos. Mar. 31**		**12 mos.**	**For the year ended December 31**				
(CA$ millions where applicable)	**2012**	**2011**	**Mar. 31.12**	**2011**	**2010**	**2009**	**2008**	**2007**
EBIT interest coverage	2.25	2.27	2.26	2.26	2.24	2.23	2.11	2.08
Total debt in capital structure	68.5%	68.4%	68.5%	68.0%	68.0%	67.9%	68.0%	67.8%
Cash flow/Total debt	19.5%	18.6%	17.9%	18.0%	16.9%	15.4%	14.2%	12.9%
Distributions/Cash flow	59.6%	65.1%	64.3%	65.8%	67.1%	66.0%	73.7%	69.5%
Debt service coverage ratio (DSCR)	2.11	2.15	1.95	1.96	1.98	1.99	1.94	1.89
Net income before extra. items	27	28	114	115	119	120	117	116
Cash flow from operations	62	62	229	229	228	217	208	192

Note: Alliance adopted US GAAP in 2012; the transition to US GAAP did not have material impact on its financials.

Alliance Pipeline Limited Partnership

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Rating Considerations Details

Strengths

(1) **Competitive toll.** Alliance offers competitive tolls to the Chicago area, relative to competing pipelines, due to its new technology and more fuel-efficient operation under one management system. It also offers authorized overrun services (AOS) to the shippers, who only have to pay incremental fuel cost for AOS. Additionally, Alliance provides a more direct and shorter route to the Chicago area through U.S. farmland, compared with the more rugged terrain for NOVA Gas Transmission System Ltd., Foothills Pipe Lines Ltd. and Northern Border Partners, L.P., the main competing pipeline systems. The System's competitiveness is also supported by its ability to ship liquids-rich gas rather than just natural gas.

(2) **Take-or-pay shipper contracts.** Stability of earnings is ensured through ship-or-pay contracts to December 1, 2015, with a diversified group of 28 shippers. The composite rating of the group is estimated at BBB (high), based partly on DBRS ratings and partly on Alliance's internal credit assessment (see Shipper Group – Sorted by Credit Rating). Approximately 89% of the base capacity (the Canadian portion of the system) is committed by strong creditworthy shippers. No single shipper accounts for more than 14% of firm capacity and each shipper must pay the demand charge for its share of the firm capacity, regardless of usage, eliminating Alliance's exposure to volume risk.

(3) **Debt service coverage protection.** The Common Agreement imposes covenant protection for the creditors. Alliance must maintain: (a) senior debt not exceeding 70% of the rate base, (b) a DSCR of at least 1.25x (before cash distributions can be paid) and (c) a debt reserve account sufficient to cover six months of principal and interest payments.

(4) **Good growth potential.** Gas reserves in the Western Canada Sedimentary Basin helped by the shale gas developments (liquids-rich gas in the Montney region) should provide sufficient supply to support strong pipeline throughput volumes. Furthermore, the Alliance system is designed for cost-efficient expansion through additional compression and potential looping.

Challenges

(1) **Most shipper contracts expire in December 2015.** Alliance faces uncertainties related to obtaining new contracts after December 1, 2015. Future competition and economic conditions could force Alliance to realize lower earnings and cash flow to service the ongoing amortizing debt. In addition, Alliance's current pipeline system was designed as a bullet system with a limited number of connection points. However, this risk is mitigated by recent expansions, which help to improve Alliance service capability.

(2) **Non-investment-grade shippers.** Approximately 11% of the contracted capacity is with non-investment-grade shippers. About 5% of firm capacity is contracted to shippers that are required to post security. This security does not cover more than one year's obligations under the transportation contracts, exposing Alliance to a potential loss of earnings should the shippers be unable to fulfill their obligations.

(3) **Cross-default features.** The senior secured debt of Alliance Canada and Alliance USA contains cross-default provisions, whereby an event of default by one entity constitutes an event of default by the other. As a result, should Alliance USA's credit profile weaken, it could have a negative impact on Alliance Canada's credit profile.

(4) **Relatively high debt leverage.** The Partnership's total debt leverage of 68.5% is relatively high. As Alliance is expected to continue to transform itself into a more conventional pipeline system, this may require substantial capital expenditures, which could place pressure on the balance sheet.

Alliance Pipeline Limited Partnership

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Earnings

(CA$ millions)	USGAAP 3 mos. Mar. 31 2012	USGAAP 3 mos. Mar. 31 2011	12 mos. Mar. 31.12	CGAAP For the year ended December 31 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008	CGAAP 2007
Net revenues	106	108	455	457	457	449	444	418
Operating, maintenance & other	27	27	133	133	126	119	114	86
EBITDA	79	81	322	324	331	331	330	332
Depreciation & amortization	30	30	119	119	124	120	114	114
EBIT	49	51	202	204	214	213	216	218
Interest expense	22	22	90	90	95	96	102	105
Other income (expense), net	0	(0)	1	1	1	2	4	3
Earning before taxes	27	28	114	115	119	120	117	116
Income taxes	0	0	0	0	0	0	0	0
Net income	27	28	114	115	119	120	117	116
Allowed ROE	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%	11.3%
Average daily throughout (bcf/day)	1.632	1.677		1.562	1.609	1.609	1.609	1.598

Summary

- The Partnership's net income continued to slightly decline in 2011 and Q1 2012, largely reflecting a depreciating investment base. However, the annual decline has been gradual and is partially offset by earnings from new receipt-point connections.
- The firm service transportation toll increased by 1.2% to $0.925/mcf effective January 1, 2012, which also partially offset the decline in earnings.
- The take-or-pay contracts with the shippers eliminate Alliance's exposure to volume risk through December 1, 2015.
- AOS remained stable at near 20% in 2011 and over 20% in Q1 2012. The AOS represents: (a) Alliance's additional services to shippers at no extra cost apart from the associated fuel requirements and (b) the competitiveness of its pipeline system.

Outlook

- Earnings are expected to continue to gradually decline through the end of the contracts, reflecting the depreciating investment base. However, this decline should be partially offset by recent capital spending associated with new receipt-point connections.

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Financial Profile

(CA$ millions)	USGAAP 3 mos. Mar. 31 2012	USGAAP 3 mos. Mar. 31 2011	12 mos. Mar. 31.12	CGAAP For the year ended December 31 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008	CGAAP 2007
Net income bef. non-recurring items	27	28	114	115	119	120	117	116
Depreciation & amortization	30	30	119	119	124	120	114	114
Deferred income taxes and other	5	4	(4)	(5)	(15)	(23)	(24)	(37)
Cash flow from operations	62	62	229	229	228	217	208	192
Distributions	(37)	(41)	(147)	(151)	(153)	(143)	(153)	(134)
Capital expenditures	(2)	(2)	(0)	(0)	(12)	(3)	(47)	(36)
Free cash flow	23	20	81	78	63	70	8	23
Changes in working capital	12	15	5	8	(4)	2	4	(6)
Net free cash flow	35	35	86	87	59	72	12	17
Net investment/Trust acct.	(35)	(35)	0	0	0	0	0	(12)
Net change in equity	0	0	(1)	(1)	0	1	4	12
Net change in debt	0	0	(73)	(73)	(68)	(55)	(28)	(17)
Other	1	0	2	1	10	(14)	22	(1)
Change in cash	1	0	15	14	1	4	10	(2)
Total debt (CA$ millions)	1,278	1,344	1,278	1,272	1,344	1,411	1,466	1,493
Total debt in capital structure	68.5%	68.4%	68.5%	68.0%	68.0%	67.9%	68.0%	67.8%
Cash flow/Total debt	19.5%	18.6%	17.9%	18.0%	16.9%	15.4%	14.2%	12.9%
EBIT interest coverage (times)	2.25	2.27	2.26	2.26	2.24	2.23	2.11	2.08
Distributions/Cash flow	59.6%	65.1%	64.3%	65.8%	67.1%	66.0%	73.7%	69.5%
Debt service coverage ratio	2.11	2.15	1.95	1.96	1.98	1.99	1.94	1.89

Summary

- Alliance Canada's financial profile remains stable, with key credit metrics remaining within DBRS's current rating parameters.
- The debt-to-capital ratio also remained stable, but was relatively high at 68.5%. However, DBRS views this leverage level as manageable, given strong and stable cash flow.
- Strong free cash flow was generated in 2011, given minimal maintenance capex.
- Most of the short-term variation reflects the change in non-cash revenue adjustments, which represented the difference between expenses included in the financial statements and expenses included in transportation tolls. This difference will be included in the tolls in future periods to be recovered from or returned to shippers.
- Cash distributions to partners are calculated by using estimated net income for the year plus 30% of depreciation expense included in the toll filings for that year. The remaining 70% of depreciation is used to fund the principal payment on the Senior Secured Notes.
- As a result of the senior debt amortization, debt levels gradually decline. However, the debt-to-capital ratio remained stable, reflecting a declining equity base.
- The DSCR at or near 2.00x is viewed as strong compared with the DSCR of 1.25x in the covenant. Alliance can only make cash distributions to its owners as long as the DSCR remains at or above 1.25x.
- The senior secured debt of Alliance USA and Alliance Canada contain cross-default provisions, whereby an event of default by one entity constitutes an event of default by the other. As a result, if Alliance USA's credit profile weakens, it could have a negative impact on Alliance Canada's credit profile.

Outlook

- Alliance Canada has estimated capex of $13.6 million for 2012, which includes the development of a new gas management system and pipeline maintenance. This amount is viewed as modest.
- Cash flow is expected to remain stable through the end of the transportation contracts, with cash distributions expected to be maintained at net income plus 30% of depreciation.
- DBRS expects Alliance to maintain the DSCR at the current level throughout the remaining life of the contracts.
- Post 2015, DBRS believes that with its cost-competitive position and the ability to ship liquids-rich gas, Alliance would not have much trouble renewing or obtaining reasonable contracts. DBRS also believes that future contracts will likely be much shorter, compared to current shipper contracts.

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Report Date:
July 6, 2012

Long-Term Debt Maturities and Bank Lines

(1) **Liquidity**
- The Partnership has a $200 million (expandable to $300 million) credit facility maturing in October 2015, with the term extendible annually for an additional year.
- The facility consists of $80 million available for letters of credit in support of Alliance's debt service reserve requirements and a $120 million operating line of credit.
- Liquidity remained strong at March 31, 2012, reflecting stable cash flow from the pipeline business, $118 million in the undrawn bank facility, given modest capex and stable cash flow from operations.
- The facility is secured by transportation contracts and debt service trust accounts, a floating charge on real and tangible properties and cross-collateralization to certain assets of Alliance USA.

(2) **Debt Maturity**

Debt Maturities (including credit facility and deferred charges)

(As of December 31, 2011)	2012	2013	2014	2015	2016	Beyond	Total
(CA$ millions)	78	80	83	90	83	864	1,278
	3.1%	6.5%	6.5%	6.8%	7.2%	69.9%	100.0%

- The above table shows the scheduled principal repayments of long-term debt as at December 31, 2011. DBRS believes that the repayment schedule is manageable.

(3) **Senior Notes**

Long-Term Debt	**Mar. 31**
(CA$ millions)	**2012**
Senior Secured Notes	
7.230% due 2015	121
7.181% due 2023	321
5.546% due 2023	171
7.217% due 2025	253
6.765% due 2025	289
4.928% due 2019 (Senior Unsecured)	120
	1,276
Credit facility	2
	1,278
Current portion	(78)
Total	**1,200**

- All Senior Secured Notes are amortized debt, and pay interest and principal semi-annually.
- The 4.928% Senior Unsecured Notes are non-amortizing.
- Alliance Canada's senior secured debt contains cross default provisions to Alliance USA's debt.

(4) **Financial Covenants and Debt Service Reserve**
- Senior debt-to-rate base of 70% and debt service coverage ratios of 1.25x to be met before any cash distributions can be made, increasing to 1.40x if pipeline shipments are below 910 mmcf/d (69% of the 1.325 bcf/d contracted).
- Alliance is required to maintain a debt service reserve equal to principal and interest payments in the following six-month period. The Partnership meets this requirement with letters of credit.
- The Partnership was in compliance as of March 31, 2012.

Alliance Pipeline Limited Partnership

Report Date:
July 6, 2012

Shipper Group – Sorted By Credit Rating

Summary

DBRS Investment-Grade Rating*	Volume (%)	Cumulative Volume (%)
A (high)	1.1%	1.1%
A	25.2%	26.3%
A (low)	17.2%	43.5%
BBB (high)	14.8%	58.3%
Not rated - considered investment grade*	31.0%	89.3%
Security Required		4.8%
Shippers considered creditworthy by DBRS		5.9%
		100.0%

* Including ratings in accordance with DBRS Internal Assessment policy. These ratings incorporate the use of non-public internal assessments on certain shippers, some of which are also major subsidiaries.

- The credit quality of the shipper group remains strong with an estimated composite rating of BBB (high) largely on a weighted-average and internal credit assessment basis. Virtually all of the capacity is contracted on a take-or-pay basis with shippers.
- Eighty-nine percent of firm capacity is contracted with investment-grade shippers, which reduces credit risk.

Alliance Pipeline Limited Partnership

Report Date:
July 6, 2012

Regulation/Transportation Contracts

Alliance Canada
(1) Canadian tolls are subject to the jurisdiction of the National Energy Board using the cost-of-service methodology. Under 15-year contracts, the tariff permits the pass-through of the following:

- Negotiated depreciation rate.
- Interest costs based on deemed capital structure of 70% debt (regardless of Alliance's actual capital structure).
- Allowed return on equity (ROE) of 11.26% (after tax) in Canada based on the 30% deemed equity component.
- Provision for income taxes using the flow-through method of accounting.
- Recovery of operating and maintenance expenses.
- The costs are on annual basis and assume a minimum Firm Capacity of 1.325 bcf. Alliance Canada collects these charges on a monthly basis.
- The fixed component of the toll must be paid, regardless of the volume of shipments.
- An additional $0.04 per mcf surcharge for receipt points in British Columbia is to compensate for the longer shipping distance.

2012 Tolling

- Effective January 1, 2012, Alliance's firm transportation toll increased by 1.2% to $0.925/mcf. This increase is due primarily to an increase in the negotiated shipper depreciation rates, increased expenditures for pipeline maintenance and system integrity and higher labour costs.
- These increased expenditures are partially offset by a decrease in the ROE due to a depreciating investment base and lower interest payments as the debt is amortized.

Alliance USA
(2) U.S. tolls are regulated by the Federal Energy Regulatory Commission.

- Negotiated depreciation rate.
- Allowed ROE of 10.88% (after tax), based on a deemed equity of 30%.
- Provision for income taxes under the normalized method of accounting.
- Renewal incentive: five-year notice requirement for non-renewal of the contract to be provided annually, beginning in year ten (2010). At the end of 2010, only 8% of the original shippers agreed to extend the contract through 2016.
- For non-renewal, prepayment of some of the depreciation expense until total depreciation recovery reaching 60% at the end of 15 years (equivalent to 4% per year; a similar rate applies to subsequent years after renewal) is required.
- No depreciation acceleration provision in the Canadian contracts; five-year non-renewal notice was required.

For the System, all AOS services are offered at incremental fuel cost.

Alliance Pipeline Limited Partnership

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July 6, 2012

Alliance Pipeline Limited Partnership

Balance Sheet (CA$ millions)	USGAAP Mar. 31 2012	CGAAP Dec. 31 2011	CGAAP Dec. 31 2010	**Liabilities & Equity**	USGAAP Mar. 31 2012	CGAAP Dec. 31 2011	CGAAP Dec. 31 2010
Assets							
Cash & equivalents	2	45	31	S.T. borrowings	0	0	0
Accounts receivable	37	43	46	Accounts payable	44	29	28
Other current assets	92	4	2	Current portion L.T.D.	78	78	73
				Other current liab.	8	9	0
Total Current Assets	131	93	79	**Total Current Liab.**	130	117	101
Net fixed assets	1,579	1,607	1,725	Long-term debt	1,200	1,194	1,271
Long-term receivables	216	215	211	Other L.T. liab.	11	9	12
Intangible assets	3	3	0	Partners' equity	588	597	632
Total Assets	1,929	1,917	2,016	**Total Liab. & SE**	1,929	1,917	2,016

Balance Sheet & Liquidity & Capital Ratios	USGAAP 3 mos. Mar. 31 2012	USGAAP 3 mos. Mar. 31 2011	12 mos. Mar. 31.12	CGAAP For the year ended December 31 2011	CGAAP 2010	CGAAP 2009	CGAAP 2008	CGAAP 2007
Current ratio	1.01	1.00	1.01	0.79	0.79	0.74	0.67	0.86
Net debt in capital structure	68.5%	67.3%	68.5%	67.2%	67.5%	67.5%	67.7%	67.5%
Total debt in capital structure	68.5%	68.4%	68.5%	68.0%	68.0%	67.9%	68.0%	67.8%
Cash flow/Total debt	19.5%	18.6%	17.9%	18.0%	16.9%	15.4%	14.2%	12.9%
(Cash flow-distributions)/Capex	11.51	11.03	321	1,909	6.13	21.27	1.17	1.63
Distributions/Net income	136.7%	142.5%	129.3%	130.8%	128.4%	119.6%	130.8%	115.3%
Distributions/Cash flow	59.6%	65.1%	64.3%	65.8%	67.1%	66.0%	73.7%	69.5%
Coverage Ratios (times)								
EBIT gross interest coverage	2.25	2.27	2.26	2.26	2.24	2.23	2.11	2.08
EBITDA gross interest coverage	3.64	3.61	3.60	3.59	3.47	3.46	3.23	3.16
Fixed-charges coverage	2.25	2.27	2.27	2.27	2.25	2.25	2.14	2.10
Debt service coverage ratio (DSCR)	2.11	2.15	1.95	1.96	1.98	1.99	1.94	1.89
DSCR (reported by APLP)	1.98	1.99	1.96	1.97	1.90	2.00	2.04	2.11
Profitability Ratios								
EBITDA margin	74.2%	74.7%	70.8%	70.9%	72.4%	73.5%	74.3%	79.4%
EBIT margin	45.9%	47.0%	44.4%	44.7%	46.7%	47.5%	48.5%	52.2%
Profit margin	25.6%	26.3%	25.0%	25.2%	26.0%	26.7%	26.3%	27.7%
Return on equity	18.4%	18.2%	18.8%	18.7%	18.3%	17.7%	16.7%	16.2%
Return on capital	10.3%	10.3%	10.5%	10.6%	10.6%	10.1%	10.0%	9.9%
Deemed partners' equity	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%

Alliance Pipeline Limited Partnership

Report Date:
July 6, 2012

Ratings

Debt	Rating	Rating Action	Trend
Senior Secured Notes	A (low)	Confirmed	Stable
Senior Unsecured Notes	BBB (high)	Confirmed	Stable

Rating History

	Current	2011	2010	2009	2008	2007
Senior Secured Notes	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Senior Unsecured Notes	BBB (high)	BBB (high)	BBB (high)	BBB (high)	NR	NR

Related Research

Alliance Pipeline L.P., July 6, 2012

Note:
All figures are in Canadian dollars unless otherwise noted.

Rating Report
Report Date:
October 5, 2012
Previous Report:
November 18, 2011

DBRS
Insight beyond the rating.

Maritimes & Northeast Pipeline Limited Partnership

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The Partnership
M&NP Canada owns the Canadian segment of the 1,000-kilometre (650-mile) onshore pipeline system that ships processed natural gas from offshore eastern Canada to markets in Nova Scotia, New Brunswick and the U.S. Northeast. The Canadian mainline – with design capacity of 555,000 million British thermal units per day (mmBtu/d) – runs 567 km (352 miles) from Goldboro, Nova Scotia, to the Canada-U.S. border near St. Stephen, New Brunswick. Lateral pipelines extend to Halifax (124 km), Saint John (103 km) and Point Tupper, Nova Scotia (65 km).

Recent Actions
September 14, 2012
Assigned Issuer Rating

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
6.90% Senior Secured Notes due 2019*	A	Confirmed	Stable
4.34% Senior Secured Notes due 2019	A	Confirmed	Stable

*Cash held in an Escrow Account ($244 million at June 30, 2012) is held for the benefit of holders of these Notes.

Rating Rationale

DBRS has confirmed the Issuer Rating, along with the ratings on the 6.90% Senior Secured Notes due 2019 (6.90% Notes) and the 4.34% Senior Secured Notes due 2019 (4.34% Notes) (collectively, the Notes) issued by Maritimes & Northeast Pipeline Limited Partnership (M&NP Canada) at "A", all with Stable trends. The ratings primarily reflect the credit support available to noteholders, the favourable regulatory environment with tolls determined on a cost-of-service basis and the fully amortizing nature of the Notes to maturity.

The Reserve Engineer's Deliverability Report (Deliverability Report) issued in November 2007 concluded that, based on the restrictive methodology specified in M&NP Canada's original financing documents, available reserves are insufficient to maintain throughput of 580,000 million British thermal units per day (mmBtu/d) for the ensuing eight years (the Test), and that the Test will likely not be met in the future.

Consequently, M&NP Canada's equity owners (77% Spectra Energy Corp, 13% Emera Inc. and 10% ExxonMobil Corporation (ExxonMobil)) did not receive cash distributions between November 30, 2007, and mid-Q2 2012, when balances reached an amount sufficient to meet all remaining principal and interest payments on the 6.90% Notes. The $244 million Escrow Account balance at June 30, 2012, is expected to be distributed to the owners over the remaining term of the 6.90% Notes.

Holders of the 4.34% Notes do not share security in the Escrow Account. However, the ratings on the 4.34% Notes and the 6.90% Notes are identical, given that access to the Escrow Account does not occur until default and therefore does not affect the default risk of either issue. In addition, under the Permitted Investments definition, the Escrow Account could theoretically be funded with A (low)-rated debt instruments that mature at various dates up to November 30, 2019. This entails market risk should interest rates rise, as well as credit risk should the downgrade of certain securities result in forced sales at a loss. DBRS recognizes, however, that recovery would be more certain for the 6.90% Notes in the event of an uncured default (not expected by DBRS), given the exclusive access to the Escrow Account for these notes.

M&NP's debt service coverage ratio (DSCR) is expected to remain satisfactory (2.0 times for the 12 months ending June 30, 2012), although debt service payments rise significantly in 2013 as a result of the sculpted nature of the 4.34% Notes debt amortization schedule and do not return to the lower current levels until 2017.

Rating Considerations

Strengths
(1) Good credit support for noteholders
(2) Strong shipper group
(3) Offshore gas supplies support pipeline
(4) Good proximity to end-user markets

Challenges
(1) Development of unconventional gas reserves
(2) Disappointing offshore gas production outlook
(3) Strong competition in U.S. Northeast
(4) Relatively high tolls due to high fixed costs

Financial Information

	6 mos. ended June 30		12 mos. ended	For the year ended December 31				
(Cdn.$ millions unless otherwise noted)	2012	2011	June 30, 2012	2011	2010	2009	2008	2007
Net income before extras.	19.6	23.6	41.1	45.1	49.1	53.5	52.1	56.2
Cash flow before extras.	45.7	47.9	92.1	94.4	95.2	100.3	96.4	98.3
Total debt in capital structure	45.8%	49.5%	45.8%	47.0%	52.0%	57.0%	60.9%	67.7%
Adjusted debt/capital (excl. escrow)	65.3%	66.7%	65.3%	66.7%	67.3%	68.2%	66.0%	67.8%
Cash flow/total debt	24.4%	23.3%	24.6%	23.9%	22.2%	21.8%	21.1%	19.4%
Debt service coverage ratio (times)	3.25	3.33	1.95	2.00	2.29	2.45	1.60	1.62

Deep Panuke Project

- Encana Corporation's (Encana) Deep Panuke project is a natural gas field located offshore of Nova Scotia, approximately 250 kilometres southeast of Halifax.
- First production from Deep Panuke for delivery to M&NP Canada is expected during Q4 2012.
- Initial production rates are expected to exceed 200 million cubic feet per day (mmcf/d) (210 mmBtu/d).
- Encana has signed a long-term contract to sell all Deep Panuke output to Repsol Energy North America Corporation.
- Given the level of unutilized firm capacity on M&NP Canada, DBRS expects the Deep Panuke volumes to be shipped under existing FSAs or on an interruptible basis, rather than under a new long-term contract.

Rating Considerations Details

Strengths

(1) Since the Deliverability Report was issued in November 2007, the following levels of credit support remain available to M&NP Canada noteholders (see Credit Support for details): (a) Firm Service Agreements (FSAs), with shippers under long-term ship-or-pay contracts; (b) the Pipeline Utilization Agreement (PUA) with Sable Offshore Energy Project (SOEP) producers (mostly investment-grade companies); (c) the Mobil Backstop Agreement (Mobil Backstop) with ExxonMobil Canada (guaranteed by ExxonMobil); and (d) balances that have built up in an Escrow Account to an amount sufficient to meet all remaining scheduled principal and interest payments on the 6.90% Notes through to maturity in November 2019. Holders of the 4.34% Notes do not share security in this Escrow Account.

(2) The credit quality of the shipper group is strong. Approximately 96% of the contracted capacity (including the Mobil Backstop) is held by investment-grade (including deemed investment-grade) shippers, with the balance held by shippers providing 12-month letters of credit.

(3) Natural gas reserves in the Scotian Shelf basin provide supply for the pipeline infrastructure, although the conventional natural gas reserve outlook for the east coast of Canada has deteriorated significantly since M&NP Canada was brought into service in late 1999. Other potential supply sources for M&NP Canada, mainly Deep Panuke, could reduce M&NP Canada's excess pipeline capacity over the medium term.

(4) As the pipeline sources gas almost entirely from offshore Eastern Canada, M&NP Canada is in close proximity to the Atlantic Canada and U.S. Northeast markets. Prior to M&NP Canada, the Nova Scotia and New Brunswick markets had no access to natural gas. The New England natural gas market has good long-term growth potential, due to its underlying economic prospects and expected growth in gas-fired power generation over time. Maritimes & Northeast Pipeline, L.L.C. (M&NP U.S.) has approval to transport natural gas to Atlantic Canada through M&NP Canada if warranted by market conditions.

Challenges

(1) M&NP Canada faces rising business risk due to development of unconventional gas fields. Competition is rising as shale gas development in the Marcellus shale region significantly increases the amount of natural gas production that flows into the U.S. Northeast.

(2) Disappointing drilling results in recent years have led to considerable deterioration in the conventional natural gas reserve and production outlook for the east coast of Canada. M&NP Canada's throughput averaged 249,431 mmBtu/d during the six months ended June 30, 2012 (6M 2012), equal to 45% of its design capacity. According to best estimates in a July 2009 independent consultant's report, M&NP Canada's throughput was expected to rise from 390,000 mmBtu/d in 2009 to 501,000 mmBtu/d in 2011 (due to new production from Deep Panuke) before declining to 300,000 mmBtu/d in 2019. As a result, M&NP Canada noteholders are more reliant on the various levels of credit support in place than expected at inception, including balances in the Escrow Account for the benefit of holders of the 6.90% Notes.

(3) M&NP Canada faces strong end-user market competition into the U.S. Northeast from several major pipelines, including: Texas Eastern Transmission, LP; Algonquin Gas Transmission, LLC; Tennessee Gas Pipeline Company and Transcontinental Gas Pipe Line Company, LLC.

(4) Combined tolls for M&NP Canada and M&NP U.S. are relatively high, due to high fixed costs and low throughput relative to competing pipelines. In a low natural gas price environment, high tolls lead to low netbacks for the SOEP producers.

Regulation

M&NP Canada's tolls are regulated by the National Energy Board (NEB) based on a cost-of-service methodology.

- M&NP Canada operates under a postage stamp structure, in which the tolls charged are the same regardless of the distance the gas has been shipped.
- The FSAs provide support on a long-term ship-or-pay basis.
- Tolls are set based on capital and operating cost forecasts for the forthcoming rate-making period and are established by dividing the revenue requirement by throughput (contracted capacity under FSAs, including the impact of the Mobil Backstop).
- Firm service tolls are charged regardless of actual volumes transported.
- Interruptible services are provided to the highest bidders (subject to a floor equal to 120% of the firm service toll) and are billed only to the extent of such volumes shipped.
- In July 2010, M&NP Canada filed an application with the NEB seeking compensation for funds held in escrow and finalization of 2010 tolls.
- In June 2011, the NEB determined that no compensation would be provided for the funds held in escrow and finalized the 2010 interim tolls approved previously.
- In January 2012, the NEB approved a three-year toll settlement between M&NP Canada and its shippers covering the 2011 to 2013 period. The Company does not expect the settlement to have a material effect on M&NP Canada's credit metrics.

Earnings and Outlook

Income Statement	6 mos. ended June 30		12 mos. ended	For the year ended December 31				
(Cdn.$ millions)	2012	2011	June 30, 2012	2011	2010	2009	2008	2007
Revenues	65.7	71.8	135.6	141.7	140.7	146.2	160.9	154.9
Operating expenses	(12.0)	(13.0)	(26.1)	(27.1)	(27.3)	(20.3)	(36.0)	(22.7)
Depreciation and amortization	(24.2)	(24.0)	(48.2)	(48.0)	(46.3)	(46.3)	(43.8)	(41.6)
Other income (expense), net	1.4	1.1	2.6	2.4	1.7	1.1	2.0	1.7
Earnings before interest and taxes	30.8	35.9	63.9	69.0	68.8	80.6	83.2	92.4
Interest expense, net	(11.2)	(12.3)	(22.8)	(23.9)	(19.7)	(27.1)	(31.1)	(36.2)
Net income before taxes	19.6	23.6	41.1	45.1	49.1	53.5	52.1	56.2
Income taxes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Income before extras.	19.6	23.6	41.1	45.1	49.1	53.5	52.1	56.2
Extraordinary items (1)	1.5	0.0	2.2	0.7	0.0	0.0	0.0	0.0
Net income, as reported	21.1	23.6	43.3	45.8	49.1	53.5	52.1	56.2

(1) Gain on sale of Other Assets and Other, net in each period.

Summary

- Net income before extras declined by 17% in 6M 2012, compared with 6M 2011, mainly due to lower tolls on a declining rate base.
- Net income fell 7.5% in 2011 compared with 2010, mainly due to the declining rate base and higher interest and depreciation and amortization expenses.

Outlook

- M&NP Canada operates under cost-of-service regulation, supported by FSAs with quality shippers.
- The Company currently operates under a three-year toll settlement covering the 2011 to 2013 period.

Maritimes & Northeast Pipeline Limited Partnership

Report Date:
October 5, 2012

Financial Profile

(Cdn.$ millions)	6 mos. ended June 30 2012	2011	12 mos. ended June 30, 2012	For the year ended December 31 2011	2010	2009	2008	2007
Net income before extraordinary items	19.6	23.6	41.1	45.1	49.1	53.5	52.1	56.2
Depreciation and amortization	24.5	24.3	48.8	48.6	46.9	47.5	44.9	42.7
Equity AFUDC and Other	1.5	0.0	2.2	0.7	(0.7)	(0.7)	(0.6)	(0.5)
Cash flow from operations	45.7	47.9	92.1	94.4	95.2	100.3	96.4	98.3
Capital expenditures	(0.9)	(0.2)	(5.9)	(5.2)	(2.1)	(3.0)	(2.2)	(6.3)
Working capital changes	(2.9)	(1.0)	1.8	3.8	(5.5)	(4.2)	14.5	(1.0)
Free cash flow before distributions	41.8	46.8	88.0	93.0	87.6	93.1	108.8	91.0
Other (mainly Escrow Account injections)	4.0	(61.9)	(25.5)	(91.5)	(54.5)	(74.4)	(57.8)	0.0
Distribution to partners	(23.0)	0.0	(23.0)	0.0	0.0	0.0	0.0	(47.9)
Net free cash flow	22.8	(15.1)	39.5	1.5	33.1	18.7	51.0	43.2
Increase (decrease) in debt	(19.5)	(17.5)	(37.0)	(35.0)	(30.5)	(0.7)	(50.1)	(41.9)
Decrease (increase) in cash balances	(3.3)	32.6	(2.4)	33.5	(2.6)	(18.0)	(0.9)	(1.3)
Funding sources	(22.8)	15.1	(39.5)	(1.5)	(33.1)	(18.7)	(51.0)	(43.2)
Funds held in escrow	244.0	214.0	244.0	248.0	187.9	132.9	58.5	0.7
Total debt	374.8	411.9	374.8	394.4	429.4	459.9	457.7	507.8
Total debt in capital structure	45.8%	49.5%	45.8%	47.0%	52.0%	57.0%	60.9%	67.7%
Adjusted debt/capital (excl. escrow)	65.3%	66.7%	65.3%	66.7%	67.3%	68.2%	66.0%	67.8%
Debt service coverage ratio (times)	3.25	3.33	1.95	2.00	2.29	2.45	1.60	1.62

Summary

- Relatively strong cash flow and low sustaining capex allow debt repayments to be made as scheduled.
- As a result of the failed Test, balances built up in the Escrow Account between November 30, 2007, and mid-Q2 2012, for the benefit of holders of the 6.90% Notes, rather than being distributed to the owners.
- This continued until mid-Q2 2012, when cash balances were built up to an amount sufficient to meet all remaining scheduled principal and interest payments on the 6.90% Notes until maturity in November 2019.
- As a result of the above, M&NP Canada paid a $23 million dividend in Q2 2012 and its total debt-to-capital ratio reached its low point (46% at June 30, 2012, compared with 70% at year-end 2006).
- This decline in balance sheet leverage was mainly due to continued debt amortization and a rising equity base, given the suspension of distributions to owners and the corresponding escrow build-up.
- However, DBRS believes that its adjusted debt-to-capital ratio (which removes the escrow balance from the partners' equity account, given that the pipeline has no access to the funds except at default and has remained in the mid-to-high-60% range since year-end 2007) is a more relevant measure.

Outlook

- M&NP Canada operates under cost-of-service regulation, supported by FSAs with quality shippers.
- The Company currently operates under a three-year toll settlement covering the 2011 to 2013 period.
- M&NP's DSCR is expected to remain satisfactory (2.0 times for the 12 months ending June 30, 2012).
- However, debt service payments related to the Notes rise significantly in 2013 as a result of the sculpted nature of the 4.34% Notes debt amortization schedule (see Debt Maturities) and do not return to the lower 2012 levels until 2017.

Maritimes & Northeast Pipeline Limited Partnership

Report Date:
October 5, 2012

Debt Maturities

The Notes are secured by a first floating charge on all assets, including assignment of all material contracts of M&NP Canada.

- $260 million 6.90% Senior Secured Notes, maturing on November 30, 2019, payable in 20 equal semi-annual payments, commencing May 31, 2010.
- $180 million 4.34% Senior Secured Notes, maturing on November 30, 2019, payable in 20 semi-annual payments, commencing May 31, 2010.

Debt Maturities (as of Dec. 31, 2011)	2012	2013	2014	2015
Debt Repayment (CAD millions) (1)	35.0	56.6	56.6	56.6
Interest Expense (2)	21.0	18.6	15.5	12.4
Total Debt Service (Repayment + Interest)	**56.0**	**75.2**	**72.1**	**69.0**
% of long-term debt	9.3%	15.1%	15.1%	15.1%

Debt Maturities (as of Dec. 31, 2011)	2016	2017	2018	2019	Total
Debt Repayment (CAD millions) (1)	53.9	50.3	35.0	30.5	374.5
Interest Expense (2)	9.3	6.3	3.6	1.5	88.2
Total Debt Service (Repayment + Interest)	**63.2**	**56.6**	**38.6**	**32.0**	462.7
% of long-term debt	14.4%	13.4%	9.3%	8.1%	100.0%

(1) Excludes $19.9 million of subordinated notes with members due on November 30, 2019. (2) DBRS estimates.

- Debt service payments related to the Notes rise significantly in 2013 as a result of the sculpted nature of the 4.34% Notes debt amortization schedule and do not return to the lower 2012 levels until 2017.

M&NP Canada Owners

Maritimes & Northeast Pipeline Limited Partnership Owners	Ownership	DBRS Rating
Spectra Energy Corp (through Spectra Energy MNEP Holdings Limited Partnership and Spectra Energy Midstream Holdings Limited Partnership) (1)	76.76%	BBB (high)
Emera Inc. (through NSP Pipeline Incorporated)	12.79%	BBB (high)
ExxonMobil Corporation (through ExxonMobil Canada Hibernia Finance Ltd.)	9.45%	NR
Maritimes & Northeast Pipeline Management Ltd.	1.00%	NR
Total	100.00%	

(1) DBRS rating applies to Spectra Energy Capital, LLC, a wholly owned subsidiary of Spectra Energy Corp.

Spectra Energy Corp, the majority owner, operates the M&NP Canada and M&NP U.S. pipeline systems.

DBRS

Maritimes & Northeast Pipeline Limited Partnership

Report Date:
October 5, 2012

M&NP Canada Shipper Group

Maritimes & Northeast Pipeline Limited Partnership - Firm Transportation Shipper List

Investment-Grade Shippers	DBRS Rating	Volume (mmBtu/d)	Volume (%)	Initial Term (years)	Maturity
Exxon Mobil Canada Limited (1)(2)	NR	174,411	40.2%	20	30-Nov-2019
Exxon Mobil Canada Products Ltd. (Backstop)(1)(2)	NR	25,558	5.9%	20	30-Nov-2019
Shell Energy North America (Canada) Inc. (2)	NR	103,163	23.8%	15	30-Nov-2014
Emera Energy Incorporated (3)	BBB (high)	1,000	0.2%	20	31-Jul-2021
Nova Scotia Power Inc. (4)	A (low)	100	0.0%	10	31-Oct-2013
New Brunswick Power Holding Corporation (5)	A (high)	43,500	10.0%	15	30-Nov-2015
Subtotal – investment-grade shippers		347,732	80.1%		
Supported by the Letters of Credit					
Cavendish Farms Corporation (6)	NR	8,000	1.8%	2	31-Mar-2013
Enbridge Gas New Brunswick Inc.	NR	11,168	2.6%	15	Various - 2021
Subtotal – supported by letters of credit		19,168	4.4%		
Other					
ExxonMobil Canada Properties	NR	3,600	0.8%	20	30-Jun-2021
Irving Oil Ltd.*	NR	48,000	11.1%	15	Various 2015-16
J.D. Irving Ltd.*	NR	15,500	3.6%	15	Various Dec. 2015
Subtotal – Other		67,100	15.5%		
Total		434,000	100.0%		
Design capacity: 555,000 mmBtu/d.					
* Deemed investment grade			% Design Capacity		
Sable Shippers (PUA) (7)	Various	530,000	95.5%	20	30-Nov-2019
Mobil Oil Canada (backstop) (8)		434,000	78.2%	20	30-Nov-2019
Outstanding shipper contracts (excluding Backstop)		408,442	73.6%		

(1) Guaranteed by Exxon Mobil Corp.
(2) Not rated by DBRS, but considered investment grade.
(3) Guaranteed by Emera Inc., which is rated BBB (high) with a Negative trend by DBRS.
(4) 100% owned subsidiary of Emera Inc.
(5) 100% owned subsidiary of Province of New Brunswick, which is rated A (high).
(6) Contract decreased to 8,000 Dth/d effective April 1, 2012.
(7) Pipeline utilization agreement (PUA) could be activated, if gas is produced.
(8) If unsubscribed and not covered by PUA.

- The credit quality of the shipper group is strong. M&NP Canada currently has 408,442 mmBtu/d of contracted capacity (74% of design capacity) with a remaining weighted-average term of about five years.
- Approximately 96% of the contracted capacity (including the Mobil Backstop) is held by investment-grade (including deemed investment-grade) shippers.
- The balance is held by shippers providing 12-month letters of credit or shippers that have been deemed investment-grade.
- The Cavendish Farms Corporation contract expires on March 31, 2013 (see above table). If this capacity is not resold, then effective April 1, 2013, contracted capacity would decline to 400,442 mmBtu/d (72% of design capacity), of which 97% (including the Mobil Backstop) would be held by investment-grade (including deemed investment-grade) shippers.
- However, the unsubscribed capacity for this contract would remain eligible for recovery under the Mobil Backstop, which would ensure that M&NP Canada would continue to receive revenues based on the minimum threshold of contract capacity (434,000 mmBtu/d, equal to 78% of design capacity for M&NP Canada) for the term of the M&NP Canada Notes.

DBRS

Maritimes & Northeast Pipeline Limited Partnership

Report Date:
October 5, 2012

Credit Support

Since the Deliverability Report was issued in November 2007, the following levels of credit support remain available to M&NP Canada noteholders:

(1) FSAs with M&NP Canada shippers provide support on a ship-or-pay basis, with original terms ranging from ten to 20 years.
- Shippers are required to pay demand charges for the pipeline, which are designed to cover fixed costs (including interest and depreciation expenses), regardless of volumes shipped.
- Variable costs are charged on a volumetric basis if gas is shipped.
- At least 85% of contracted volumes must be held by investment-grade (including deemed investment-grade) shippers (currently 96%, including the Mobil Backstop) and the remaining weighted-average term of the FSAs is approximately five years, as some contracts expire prior to maturity of the Notes.
- The remaining commitments are supported by 12-month letters of credit or are with shippers deemed to be investment-grade.
- Accordingly, investment-grade shippers may not assign their contract capacity to deemed investment-grade shippers if, after such an assignment, the latter would account for more than 15% of total contract capacity.

(2) The PUA requires SOEP producers (mostly strong investment-grade companies), on a several basis, to use M&NP Canada's pipeline system (530,000 mmBtu/d, equal to 95% of design capacity) for the term of the M&NP Canada Notes.
- If gas is produced and shipped by alternative means, the producers are still committed to paying an equivalent reservation fee for such diverted gas.
- Sable Offshore Energy Inc. (SOEI), operator of SOEP, would have an incentive to continue to produce gas.
- The only other likely reasons for SOEI to not produce gas would be a lack of sufficient reserves or an inability to recover its variable production costs.

(3) The Mobil Backstop stipulates that ExxonMobil Canada (guaranteed by ExxonMobil) will pay for unsubscribed pipeline capacity to a maximum of 164,760 mmBtu/d. Combined with ExxonMobil's FSA for 269,240 mmBtu/d, this implies that ExxonMobil ensures that certain minimum threshold revenues will be achieved (based on 434,000 mmBtu/d, equal to 78% of design capacity for M&NP Canada) for the term of the M&NP Canada Notes.
- The backstopped capacity is reduced by M&NP Canada's currently effective FSAs.
- Effectively, the Mobil Backstop provides important revenue support in the event of non-renewal by certain original investment-grade shippers with FSAs that expire prior to the maturity of the M&NP Canada Notes.

(4) The Deliverability Report, issued in November 2007, concluded that, based on the restrictive methodology specified in the M&NP Canada financing documents, available reserves are insufficient to maintain throughput of 580,000 mmBtu/d for the ensuing eight years and that the Test will likely not be met in the future. M&NP Canada currently has 408,442 mmBtu/d of firm contracted capacity.
- Consequently, balances built up in the Escrow Account from November 30, 2007, to mid-Q2 2012 for the benefit of holders of M&NP Canada's 6.90% Notes, rather than being distributed to the equity owners.
- In mid-Q2, 2012 balances had increased to an amount sufficient to meet all remaining scheduled principal and interest payments on the 6.90% Notes until maturity in November 2019.
- Holders of the 4.34% Notes do not share security in the Escrow Account.
- Therefore, holders of the 6.90% Notes have the benefit of this protection, which was the intention when the original M&NP Canada financing was completed in 1999.
- However, under the Permitted Investments definition, the Escrow Account could theoretically be fully funded with A (low)-rated debt instruments that mature at various dates up to November 30, 2019. This entails market risk should interest rates rise substantially, as well as credit risk should the downgrade of certain securities result in forced sales at a loss.

Maritimes & Northeast Pipeline Limited Partnership

Report Date:
October 5, 2012

Maritimes & Northeast Pipeline Limited Partnership (M&NP Canada)

Balance Sheet (Cdn.$ millions)	June 30 2012	Dec. 31 2011	Dec. 31 2010		June 30 2012	Dec. 31 2011	Dec. 31 2010
Assets				**Liabilities and Equity**			
Cash and equivalents	6.4	3.1	36.6	A/P & accrued liab.	5.4	5.3	5.3
Accounts receivable	12.6	14.2	15.2	Regulatory liabilities	2.3	4.1	1.9
Other current assets	56.2	39.7	4.3	LT debt due in one year	45.8	35.0	35.0
Current Assets	75.2	57.0	56.1	**Current Liabilities**	53.5	44.4	42.1
Net fixed assets	517.8	541.4	583.9	Long-term debt	329.0	359.4	394.4
Other long-term assets	233.6	252.7	193.2	Other long-term liab.	0.6	2.1	0.2
Total	826.6	851.0	833.2	Partners' equity	443.4	445.2	396.5
				Total	826.6	851.0	833.2

Balance Sheet and Liquidity Ratios	6 mos. ended June 30 2012	6 mos. ended June 30 2011	12 mos. ended June 30, 2012	For the year ended December 31 2011	2010	2009	2008	2007
Current ratio	1.41	1.40	1.41	1.28	1.33	1.37	0.22	0.82
Adjusted debt/capital (excl. escrow)	65.3%	66.7%	65.3%	66.7%	67.3%	68.2%	66.0%	67.8%
Total debt in capital structure	45.8%	49.5%	45.8%	47.0%	52.0%	57.0%	60.9%	67.7%
Net debt in capital structure	45.4%	49.3%	45.4%	46.8%	49.8%	55.1%	60.0%	67.1%
Partners' equity in capital structure	54.2%	50.5%	54.2%	53.0%	48.0%	43.0%	39.1%	32.3%
Deemed partners' equity	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	31%	29%
Cash flow/total debt	24.4%	23.3%	24.6%	23.9%	22.2%	21.8%	21.1%	19.4%
Partners' withdrawal/net income	117%	0%	56%	0%	0%	0%	0%	85%
Accum. Dep./gross fixed assets	50%	45%	50%	47%	43%	39%	35%	31%
Coverage Ratios (times) (1)								
EBIT interest coverage	2.76	2.92	2.80	2.88	3.46	2.95	2.66	2.54
EBITDA interest coverage	4.95	4.91	4.93	4.91	5.84	4.70	4.10	3.72
Fixed-charges coverage	2.76	2.92	2.80	2.88	3.46	2.95	2.66	2.54
Debt service coverage ratio	3.25	3.33	1.95	2.00	2.29	2.45	1.60	1.62
Profitability Ratios								
Operating margin	44.8%	48.4%	45.2%	47.0%	47.7%	54.4%	50.4%	58.5%
Profit margin	29.9%	32.9%	30.3%	31.8%	34.9%	36.6%	32.3%	36.3%
Allowed return on equity	n.a.	n.a.	n.a.	n.a.	11.7%	11.7%	11.6%	12%
Return on partners' equity	8.8%	11.6%	9.5%	10.7%	13.2%	16.7%	19.4%	23.6%
Return on capital	7.4%	8.7%	7.7%	8.3%	8.4%	10.3%	11.1%	12.0%
Selected Data (Cdn.$ millions)								
Revenues	65.7	71.8	135.6	141.7	140.7	146.2	160.9	154.9
Operating income	29.4	34.8	61.3	66.6	67.1	79.5	81.1	90.6
Equity AFUDC	0.0	0.0	0.0	0.0	0.7	0.7	0.6	0.5
Net income before extras.	19.6	23.6	41.1	45.1	49.1	53.5	52.1	56.2
Extraordinary items	1.5	0.0	2.2	0.7	0.0	0.0	0.0	0.0
Net income, as reported	21.1	23.6	43.3	45.8	49.1	53.5	52.1	56.2
Cash flow from operations	45.7	47.9	92.1	94.4	95.2	100.3	96.4	98.3
Capital expenditures	(0.9)	(0.2)	(5.9)	(5.2)	(2.1)	(3.0)	(2.2)	(6.3)
Changes in non-cash work. capital	(2.9)	(1.0)	1.8	3.8	(5.5)	(4.2)	14.5	(1.0)
Free cash flow bef. distributions	41.8	46.8	88.0	93.0	87.6	93.1	108.8	91.0
Other (2)	4.0	(61.9)	(25.5)	(91.5)	(54.5)	(74.4)	(57.8)	0.0
Distribution to partners	(23.0)	0.0	(23.0)	0.0	0.0	0.0	0.0	(47.9)
Net free cash flow	22.8	(15.1)	39.5	1.5	33.1	18.7	51.0	43.2
Operating Statistics								
Average rate base (Cdn.$ millions)	538.4	581.2	n.a.	581.2	591.2	634.0	676.2	717.6
Pipelines (kilometres)	876	876	876	876	876	876	876	876
Throughput volume (mmBtu/day)	249.4	290.1	n.a.	284.4	329.5	362.6	473.2	428.1
Capacity (mmBtu/day)	555	555	555	555	555	555	555	555
Load factor	45%	52%	n.a.	51%	59%	65%	85%	77%

(1) Excludes AFUDC and capitalized interest.

(2) Includes net purchases of available-for-sale securities in 2008, 2009, 2010, 2011 and interim periods. n.a. = not applicable.

Maritimes & Northeast Pipeline Limited Partnership

Report Date:
October 5, 2012

Ratings

Debt	Rating	Rating Action	Trend
Issuer Rating	A	Confirmed	Stable
6.90% Senior Secured Notes due 2019*	A	Confirmed	Stable
4.34% Senior Secured Notes due 2019	A	Confirmed	Stable

*Cash held in an Escrow Account ($244 million at June 30, 2012) is held for the benefit of holders of these Notes.

Rating History

	Current	2011	2010	2009	1999-2008
Issuer Rating	A	NR	NR	NR	NR
6.90% Senior Secured Notes due 2019*	A	A	A	A	A
4.34% Senior Secured Notes due 2019	A	A	A	A	NR

*Cash held in an Escrow Account ($244 million at June 30, 2012) is held for the benefit of holders of these Notes.

Note:
All figures are in Canadian dollars unless otherwise noted.

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Summary:
Alliance Pipeline Limited Partnership

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Summary:

Alliance Pipeline Limited Partnership

Rationale

The Alliance Pipeline System is a 1,875-mile natural gas pipeline, with 450 miles of laterals, extending from the Western Canadian Sedimentary Basin (WCSB) to the Chicago Market Hub. The pipeline delivers about 1.6 billion cubic feet per day to 11 interconnections in Chicago, from more than 50 receipt points in northwestern Alberta and northeastern British Columbia. The Alliance System consists of two limited partnerships: Alliance Pipeline L.P. (Alliance U.S.), which is owned by Enbridge Inc. (50%, A-/Stable/--) and Veresen Inc. (50%, BBB/Stable/--), and Alliance Pipeline Limited Partnership (Alliance Canada), which is owned by Enbridge Income Fund (50%; not rated) and Veresen Inc. (50%). The two partnerships own portions of the undivided pipeline and rely on cash flow generated from capacity contracts on the entire pipeline. The partnership's financial profiles depend on one another due to cross-default provisions.

Standard & Poor's Ratings Services' 'BBB+' rating on the pipeline reflects our view of the project's strengths:

- Alliance System's unique ability to transport natural gas and natural gas liquids improves its competitive advantage and provides shippers with additional economic incentives to use the pipeline.
- Substantially all of Alliance System's capacity is contracted under firm ship-or-pay contracts under a competitive tariff, with a diverse basket of shippers (the largest shipper accounts for 13% of capacity). The contracts expire in December 2015.
- The weighted-average credit rating of shippers is 'BBB'. Management can require low-rated shippers to post up to one year of charges as collateral.
- An amortizing debt structure, a 70% leverage covenant, and six-month debt service reserves strengthen Alliance System's financial profile.

The following risks offset the strengths at the 'BBB+' rating level:

- Supply depends on gas production in the WCSB, which has had declining production over the past several years and may continue to decline.
- Much of the debt matures well after the existing contracts are set to expire in 2015.

We view the Alliance System as stable. Its competitive position has improved, which offsets greater medium-term recontracting risk, in our view. Management plans to migrate from a point-to-point "bullet" pipeline to a multiservice business model over the next few years and offer short-haul and other hub services. Although the expiring contracts (about 92% of shippers chose not to renew their contracts) expose Alliance to recontracting risk, we believe the multiservice model enhances the pipeline's competitive advantage and improves its ability to remarket capacity that becomes available after 2015. In particular, Alliance's ability to transport high amounts of natural gas liquids contained in the gas stream to downstream processing markets may provide shippers with additional economic incentives to use the pipeline once contracts expire.

In our view, the steady-to-slowing pace of gas development and production in the WCSB should have limited effects on Alliance Canada in the immediate future. The ship-or-pay contracts mitigate this risk through 2015, and the pipeline has announced several expansions to enhance gas receipts to maintain and increase usage. The Montney Shale and Horn River Basin in Canada, as well as the Bakken Shale in North Dakota, may offset the decline in the WCSB.

The Alliance Pipeline system continues to demonstrate strong financial performance. Debt service coverage ratios (DSCR) for the U.S.-based and Canada-based portions of the pipeline have remained consistent. DSCRs as of June 30, 2012, were 1.83x for Alliance U.S. and 1.94x for Alliance Canada, and we expect them to remain steady in the near future due to the take-or-pay contracts.

Liquidity

The project generates "adequate" (as our criteria define the term) liquidity to meet its debt service obligations. We expect Alliance U.S. to produce funds from operations of about $180 million, which it uses to fund annual maintenance capital expenditures of less than $5 million, service annual debt amortizations of about $65 million, and sponsor distributions of about $30 million. As of June 30, 2012, the partnership had $104 million available under its $125 million revolving credit facility, which matures on Oct. 30, 2015.

We expect Alliance Canada to produce about C$240 million in funds from operations, which it uses to fund annual capital expenditures of less than $5 million, service annual debt amortization of about $80 million, and distribute dividends of about $140 million to sponsors. As of June 30, 2012, about C$198 million remained available on the Canadian partnership's C$200 million revolving credit facility, which also matures on Oct. 30, 2015.

A six-month debt service reserve enhances liquidity for each partnership. A $60 million letter of credit, backed by the revolving credit facility, funds the reserve for Alliance U.S. An $80 million letter of credit funds Alliance Canada; its credit facility backs the letter. Equity distributions for each partnership are restricted if the DSCR falls below 1.25x for four historical and prospective quarters.

Outlook

The stable outlook reflects Alliance System's strong competitive position, acceptable DSCR, and the various project finance structural enhancements, offset by the heightened refinancing risk. Upgrade potential is limited, but possible if Alliance pays down debt ahead of schedule such that refinancing risk is lowered and DSCRs remain above 2.5x throughout our forecast period. We could lower ratings as the contract expirations come closer and we do not become confident in the projects' abilities to enter into new contracts at acceptable rates, such that the DSCR remain above 1.5x to 1.6x.

Related Criteria And Research

Key Credit Factors: Criteria For Rating The Global Midstream Energy Industry, April 18, 2012

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Research Update:

Maritimes & Northeast Pipeline 'A' Ratings Affirmed; Outlook On One Tranche Revised To Stable From Positive

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Research Update:

Maritimes & Northeast Pipeline 'A' Ratings Affirmed; Outlook On One Tranche Revised To Stable From Positive

Overview

- We have updated our criteria for ratings based on escrowed collateral. As a result, we now cap the defeased bond rating on gas pipeline company Maritimes & Northeast Pipeline L.P. (Maritimes-Canada) by its 'A' creditworthiness because it is effectively a guarantor of the escrowed collateral of the C$260 million tranche of debt.
- We are affirming our 'A' rating on Maritimes-Canada's senior secured debt.
- We revised the outlook on the company's C$260 million senior secured notes due 2019 to stable from positive and maintained the stable outlook on the company's C$180 million senior secured notes due 2019.
- The stable outlook on Maritimes-Canada's debt reflects stable cash flows and support from a backstop agreement.

Rating Action

On July 30, 2012, Standard & Poor's Ratings Services affirmed its 'A' senior secured ratings on gas pipeline company Maritimes & Northeast Pipeline L.P. (Maritimes-Canada). In addition, we revised the outlook on the company's C$260 million senior secured notes due 2019 to stable from positive. The outlook on the company's C$180 million senior secured notes due 2019 remains stable.

Rationale

The outlook revision reflects our updated criteria for ratings based on escrowed collateral. As Maritimes-Canada is effectively a guarantor of the escrowed collateral of the C$260 million tranche of debt, we cap the defeased bond rating by its 'A' creditworthiness. We rate this tranche of debt in-line with our 'A' rating on Maritimes Canada's other tranche of debt. While the escrow cash balance for the C$260 million tranche is fully funded and represents the primary bond repayment source, Maritimes-Canada remains the guarantor of the escrowed collateral. Maritimes-Canada's two tranches of debt also have cross-default provisions.

Maritimes & Northeast Pipeline L.P.(Maritimes-Canada) and Maritimes & Northeast Pipeline LLC (Maritimes-U.S.; BBB-/Stable/--) own the Canadian and U.S. portions of a 684-mile mainline underground natural gas pipeline extending from the Sable Offshore Energy Project (SOEP) processing plant in Goldboro, Nova Scotia, through New Brunswick Province, Maine, and New

Hampshire. The pipeline delivers gas to markets in Atlantic Canada and the northeastern U.S., including New England and the greater Boston area. The owners of the Maritimes & Northeast system are Spectra Energy Corp. (77.5%; BBB+/Stable/--), Emera Inc. (12.9%; BBB+/ Negative/--), and ExxonMobil Corp. (9.6%, AAA/Stable/A-1+). Despite the physical interconnection between Maritimes-Canada and Maritimes-U.S. and identical ownership, the debt agreements between the two entities do not contain cross-collateralization provisions and have different security packages.

Maritimes-Canada has two tranches of senior secured debt that rank pari passu in debt service and have cross-default provisions. Both mature in 2019, with the C$260 million issue having an escrow account. The escrow account was triggered by the findings under a reserve engineer's deliverability report in 2007, which stated that reserves available to supply the pipeline would not meet the pipeline's maximum throughput level. As a result, distributions were halted and excess cash flow has been deposited into an escrow account in accordance with the indenture. Sufficient funds are held in the escrow account to economically defease remaining principal and interest payments on the notes.

In our view, key factors that support the 'A' ratings include:

- Contractual agreements with ExxonMobil that support the partnership if production levels at SOEP are below expectation and ensure a base level of cash flow to service debt at about 1.5x. The backstop agreement obligates ExxonMobil to pay for unsubscribed capacity up to the extent that gas is not transported or otherwise paid for, pursuant to the supplier firm service agreements (FSA) and/or the pipeline utilization agreement (PUA).
- Under the PUA, the SOEP producers are severally liable on a daily basis if FSAs on Maritimes-Canada do not cover 530,000 million Btu per day. Together with ExxonMobil's FSAs, these obligations ensure that capacity will be subscribed under FSAs or payments will be made under the PUA or the backstop at a minimum of 445,000 million Btu per day.
- Long-term FSAs for more than 75% of Maritimes-Canada's maximum capacity are currently in place.
- Credit risk is appropriate for the rating, as about 65% of contracted capacity is with shippers rated 'AA-' or higher. The other shippers are rated in the 'BBB' category or have letter-of-credit support.
- Agreements do not contain cross-default provisions with Maritimes-U.S.
- Production from EnCana Corp.'s (BBB/Stable/--) Deep Panuke field, Corridor Resources Inc.'s (not rated) McCully Gas Field, and Repsol's Canaport LNG facility help augment declining production from SOEP.

We believe the following risks partly offset the partnership's strengths:

- A potentially eroding competitive position that could reduce allowed tariff rates over time, and
- Supply concerns at SOEP.

The PUA covers shipper defaults and FSAs expiring before the bond maturity if SOEP production does not flow on the Maritimes system under the FSAs. In addition to shipper credit risk, operating risk exists because the rates under the FSAs are payable only if the pipeline is available to transport gas (subject to force majeure provisions). Given past production problems, there is some risk to current rates in our view because shippers could request a rate case with Canada's National Energy Board if the pipeline were to become less competitive. Although the board has historically been supportive of pipelines and allowed these companies to recover operating costs and to earn reasonable returns, rate pressure through the term of the debt does pose some risk for the partnership. Increasing gas supplies from the fast-growing Marcellus region could more and more be shipped to the Boston market, which is a key endpoint of the Maritimes system. While a long-term risk, the associated shorter distance to ship gas and likely lower competing shipping tariff could lessen the need to transport off-shore Canadian supplies south on the Maritimes system.

Over the intermediate term, we believe the long-term FSAs will support debt service coverage on both issues. Now that the C$260 million tranche is economically defeased, we expect debt service coverage on the other debt issue to increase significantly as amortization will increase. We view this as favorable to bondholders. Per our calculations, the backstop can support a minimum debt service coverage ratio (DSCR) through 2019 greater than 1.5x, which is adequate for a stress case at the current rating. The backstop agreements will remain in force through the term of the debt, as long as the pipeline remains available and requires payment, even if SOEP does not produce gas. Over the intermediate term, we expect DSCR of 1.8x or higher, which is adequate for the rating.

Liquidity

In our view, the project generates adequate liquidity to meet debt service requirements with its projected sources expected to exceed its uses by about 1.5x. Liquidity benefits from debt service reserves on each issue sized to cover the next semiannual debt-service payments. The debt service reserves are funded by cash and ExxonMobil sponsor notes. Liquidity also benefits from the partnership's ability to re-enter, without lender consent, two working capital facilities with total borrowing capacity of $25 million.

We expect annual cash available for debt service of about $100 million per year, which supports debt service of slightly under $60 million per year. We believe that annual maintenance capital requirements will remain below $5 million. Following the deliverability test distributions ceased, but can resume now that the C$260 million debt is fully collateralized with the escrow account maintaining sufficient funds to retire the bonds including interest. Equity distributions could resume if the DSCR is above 1.3x for the previous or forecast 12 months. Over the intermediate term, we believe that the DSCR will remain above 1.8x over the next few years.

Outlook

The stable outlook on Maritimes-Canada's debt reflects stable cash flows from the FSAs, PUAs, and support from the backstop agreement. Upward movement in our rating on Maritimes-Canada is limited due to the company's size, lack of asset diversity, and single-asset risk. While unlikely given the ExxonMobil support agreement, we would lower the rating if the DSCR declines below 1.5x for a sustained period. This would require the pipeline to be unavailable for shipment such that no payments would be expected under the FSAs, PUAs, or backstop agreement.

Related Criteria And Research

- Methodology And Assumptions: Assigning Ratings To Bonds In The U.S. Based On Escrowed Collateral, May 31, 2012
- Key Credit Factors: Criteria For Rating The Global Midstream Energy Industry, April 18, 2012

Ratings List

Ratings Affirmed; Outlook Revised

	To	From
Maritimes & Northeast Pipeline L.P.		
C$260 Mil. Senior Sec. Notes Due 2019	A/Stable	A/Positive

Ratings Affirmed

Maritimes & Northeast Pipeline L.P.	
C$180 Mil. Senior Sec. Note Due 2019	A/Stable

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McGRAW-HILL

DECISION

2012 NSUARB 227
M04972

NOVA SCOTIA UTILITY AND REVIEW BOARD

IN THE MATTER OF THE PUBLIC UTILITIES ACT

- and -

IN THE MATTER OF AN APPLICATION by **NOVA SCOTIA POWER INCORPORATED** for Approval of Certain Revisions to its Rates, Charges and Regulations, including the review of the Fuel Adjustment Mechanism Audit

BEFORE:	Peter W. Gurnham, Q.C., Chair Roland A. Deveau, Q.C., Vice-Chair Kulvinder S. Dhillon, P.Eng., Member
APPLICANT:	**NOVA SCOTIA POWER INCORPORATED** Terry Dalgleish, Q.C. John J. (Jack) Marshall, Q.C. René Gallant, LL.B. Nicole Godbout, LL.B.
INTERVENORS:	**AFFORDABLE ENERGY COALITION** Claire McNeil, LL.B. **ALTON NATURAL GAS STORAGE LP** Alan V. Parish, Q.C. **AVON GROUP** Nancy G. Rubin, LL.B. Maggie A. Stewart, LL.B. **CONSUMER ADVOCATE** John P. Merrick, Q.C. William L. Mahody, LL.B. **SMALL BUSINESS ADVOCATE** E.A. Nelson Blackburn, Q.C. Paul B. Miller, LL.B.

HALIFAX REGIONAL MUNICIPALITY
Martin C. Ward, Q.C.
Angus Doyle
Julian Boyle

LIBERAL CAUCUS OFFICE
Stephen McNeil, M.L.A.
Andrew Younger, M.L.A.
Shawn Lawlor

MUNICIPAL ELECTRIC UTILITIES OF NOVA SCOTIA CO-OPERATIVE
David MacDougall, LL.B.
Albert Dominie
Donald Regan

PROGRESSIVE CONSERVATIVE CAUCUS OFFICE
Jamie Baillie, M.L.A.
Chuck Porter, M.L.A.
Jennifer Edge

PROVINCE OF NOVA SCOTIA (Departments of Energy and Environment)
Stephen T. McGrath, LL.B.

BOARD COUNSEL:	S. Bruce Outhouse, Q.C. Richard J. Melanson, LL.B.
LIST OF PARTICIPANTS:	Appendix “A”
HEARING DATE(S):	September 13-14, 18-20, October 29-31 and November 1, 2 and 9, 2012
UNDERTAKINGS:	November 19, 2012
FINAL SUBMISSIONS:	November 30, 2012
DECISION DATE:	**December 21, 2012**
DECISION:	**Settlement Agreements approved with adjustments for pension costs and executive compensation. Three FAM related disallowances totaling $6,503,000. See Summary of Findings starting at paragraph 460.**

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1.0 INTRODUCTION

[1] This Decision is further to a public hearing conducted by the Nova Scotia Utility and Review Board (the “Board”) on September 13-14, 18-20, October 29-31, and November 1, 2 and 9, 2012, in the matter of an application by Nova Scotia Power Incorporated (“NSPI”, the “Company”, the “Utility”), dated May 8, 2012, for approval of revisions to its Rates, Charges and Regulations (the “Application” or “GRA”).

[2] Consistent with the Plan of Administration (“POA”) for NSPI's fuel adjustment mechanism (“FAM”), Liberty Consulting Group (“Liberty”) was engaged to do a comprehensive audit with respect to the FAM for the period covering 2010 and 2011 (“FAM Audit”). The POA provides that an audit of the FAM will be done every second year. Liberty filed its FAM Audit with the Board on July 10, 2012. The Board directed that its consideration of the FAM Audit would be consolidated into the hearing of NSPI's general rate application. This Decision also includes the Board's findings relative to the FAM Audit.

[3] The NSPI Application seeks the Board's approval of a Rate Stabilization Plan (“RSP”). The proposed RSP is a two-year rate plan, with net increases of three percent per year effective on each of January 1, 2013, and January 1, 2014. According to the Application, the increases will cover a portion of the increased costs forecast by NSPI in each of the next two years. NSPI proposes the remaining revenue requirement be deferred for future recovery commencing in 2015. The various elements of the proposed RSP are explained in further detail later in this Decision.

[4] The public hearing was duly advertised in accordance with sections 64 and 86 of the *Public Utilities Act*, R.S.N.S. 1989, c. 380, as amended (the "*Act*"), which read as follows:

> **Approval of schedule of rates and charges of utility**
> **64 (1)** No public utility shall charge, demand, collect or receive any compensation for any service performed by it until such public utility has first submitted for the approval of the Board a schedule of rates, tolls and charges and has obtained the approval of the Board thereof.
>
> **(2)** The schedule of rates, tolls and charges so approved shall be filed with the Board and shall be the only lawful rates, tolls and charges of such public utility until altered, reduced or modified as provided in this Act.
>
> **Notice of hearing of application for rate changes**
> **86** Notice of the hearing of any application, for the approval of or providing for an increase or decrease in the rates, tolls and charges of any public utility, shall be given by advertisement in one or more newspapers published or circulating in the cities, towns or municipalities where such changes are sought, for three consecutive weekly insertions preceding the date of said hearing, unless otherwise ordered by the Board.

[5] A total of 15 formal Intervenors responded to the application of NSPI. A number of these parties were represented at the hearing by counsel. The Small Business Advocate ("SBA"); the Consumer Advocate ("CA"); the Affordable Energy Coalition ("AEC"); Alton Natural Gas Storage LP ("Alton"); Avon Group ("Avon"), whose counsel represented 13 Intervenors; Halifax Regional Municipality ("HRM"); the Liberal Caucus Office; the Progressive Conservative Caucus Office; the Municipal Electric Utilities of Nova Scotia Co-operative ("MEUNSC"); and the Nova Scotia Departments of Energy and Environment (the "Province") all participated in the hearing. The Board also received numerous submissions from members of the public opposing NSPI's Application.

2.0 WRITTEN AND ORAL SUBMISSION FROM THE PUBLIC

[6] In the advertised Notice of Public Hearing, the public was advised that they could file submissions with the Board outlining their views regarding NSPI's Application. In response to this notification, the Board received 64 written submissions from the public and 13 individuals made presentations at the evening session on September 18, 2012.

[7] Most of the written submissions noted impacts that another rate increase would have on customers, especially on low and fixed-income customers. Some of the concerns noted were: the number of recent rate increases; executive compensation levels; rate of return and company earnings; the need for renewable energy; and employee bonuses.

[8] During the evening session, some of the same concerns were raised. Presentations were made by 10 individuals and by a representative from the Canadian Federation of Independent Business ("CFIB"), by the M.L.A. for Pictou West, and the President of the Halifax-Dartmouth and District Labour Council.

[9] The Honourable Charlie Parker, M.L.A. for Pictou West and Minister of Energy, stated that his government has heard the concerns of Nova Scotians, caused by higher electricity rates, and planned to introduce legislative amendments in the fall of 2012 to deal with executive salaries and bonuses, reducing the number of rate hearings, and dealing with the performance of NSPI in general.

[10] Leanne Hachey, representing the CFIB and 5,200 small and medium size businesses in Nova Scotia, noted that her membership cannot absorb any further increases and also cannot pass these on to its customers. She stated NSPI should find

efficiencies within its organization to pay for increased operating costs. She requested that the demand meter threshold be raised to allow additional small businesses to migrate out of this rate class.

[11] Kyle Buott, representing the Halifax-Dartmouth and District Labour Council and 25,000 union workers, stated that within the last four months his delegates have voted twice, unanimously, against the rate increase. He made three points: objecting to the process followed in the rate hearing via settlement agreement; the rate hike proposed does not reflect the cost of electricity but profit for the company; and the Board should get more input from ratepayers who live outside the Halifax area.

[12] Archie Stewart collected an electronic petition which he filed with the Board before the evening session. He noted that he was speaking on behalf of 31,334 Nova Scotia families and the Board should deny the proposed rate increase, including the Settlement Agreement.

[13] Gene McManus stated that the NSPI pension plan is being run by its employees who are also the beneficiaries of the plan. He suggested that the NSPI pension plan should be run by an independent third party.

[14] The Board considered all the comments made in the written submissions and during the evening session in making its decision on the Application. The Board is mindful of its responsibility to protect the public interest and does give due weight to the comments received from the public. The Board has to balance this with the needs of the Utility to provide a safe and reliable service at a minimum cost. No one likes rate increases; however, the Utility’s costs are increasing, similar to other businesses, and rates need to be adjusted in order to recover these cost increases.

3.0 BACKGROUND

[15] NSPI is a vertically integrated, investor-owned, regulated public utility with a virtual monopoly on electricity service throughout the province. It is the primary electricity supplier in Nova Scotia, providing over 95% of the electricity generation, transmission and distribution in the province. The *Act* gives the Board broad regulatory oversight over public utilities and provides it with the authority to discharge its regulatory responsibilities. The *Act* requires the Board to use a cost for service method for setting rates. The Board must allow NSPI to recover its prudent and proper costs of providing each type of service and a return on its rate base or capital assets.

[16] In legislation, the word “shall” is mandatory. Therefore, the Board is required to determine NSPI’s costs and assets in providing each type of service. Section 42(1) provides:

> **42(1)** The Board <u>shall fix and determine a separate rate base</u> for each type or kind of service furnished, rendered or supplied to the public by a public utility. [Emphasis added]

[17] The Board must provide a rate of return to NSPI each year. Section 45(1) reads:

> **45(1)** <u>Every public utility shall be entitled to earn annually such return</u> as the Board deems just and reasonable on the rate base as fixed and determined by the Board for each type or kind of service furnished, rendered or supplied by such public utility, provided, however, that where the Board by order requires a public utility to set aside annually any sum for or towards an amortization fund or other special reserve in respect of any service furnished, rendered or supplied, and does not in such order or in a subsequent order authorize such sum or any part thereof to be charged as an operating expense in connection with such service, such sum or part thereof shall be deducted from the amount which otherwise under this Section such public utility would be entitled to earn in respect of such service, and the net earnings from such service shall be reduced accordingly. [Emphasis added]

[18] This return must be in addition to NSPI’s prudent and proper operating expenses of providing the services. Section 45(2) states:

> **45(2)** Such return shall be in addition to such expenses as the Board may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Board according to this Act and the rules and regulations of the Board. [Emphasis added]

[19] NSPI, like all other business, experiences cost increases in virtually every expense it incurs to produce electricity for the people of Nova Scotia. The *Act* requires the Board to ensure these prudent and proper costs are recovered in NSPI's rates.

[20] A fair return on rate base is important for the sustainability of the service. A low return on rate base may cause people to not invest in the Utility. It may also lead to a poor bond rating, which may cause financial institutions to increase the rate of interest on monies NSPI needs to borrow to provide the service. This may result in NSPI's rates increasing solely to cover the additional costs of borrowing money, without even addressing the increases in the operating expenses.

[21] In addition to statutory requirements to be considered during a general rate application, the Board is also guided by long-established, fundamental ratemaking principles. In its Decision dated March 31, 2005, on a rate application by NSPI, the Board explained these guidelines as follows:

> In utility regulation, there are generally accepted principles which govern the rate-making exercise. The object of rate-making under a cost-of-service-based model is that, to the extent reasonably possible, rates should reflect the cost to the utility of providing electric service to each distinct customer class. In regulating NSPI, the Board is guided by these generally accepted principles as well as by case law.
>
> A widely-accepted publication written by Dr. James Bonbright entitled **Principles of Public Utility Rates**, sets out the following guidelines for determining appropriate rates:
>
> **CRITERIA OF A SOUND RATE STRUCTURE**
>
> 1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
>
> 2. Freedom from controversies as to proper interpretation.

3. Effectiveness in yielding total revenue requirements under the fair-return standard.

4. Revenue stability from year to year.

5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")

6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.

7. Avoidance of "undue discrimination" in rate relationships.

8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   (a) in the control of the total amounts of service supplied by the company;
   (b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).

[Decision, March 31, 2005, p. 14]

[22] The Board continues to make its decisions in accordance with the *Act,* and the principles noted above.

[23] After seeking an adjournment at the commencement of the public hearing on September 13, 2012, NSPI notified the Board on September 14th that it had reached a Settlement Agreement (the “GRA Agreement”) on many of the outstanding issues in the NSPI Application. The GRA Agreement has the support of the CA, the SBA and Avon. The Board adjourned the hearing to provide an opportunity for all other parties to review the GRA Agreement. The hearing reconvened on September 18, 2012, at which point NSPI witnesses explained the terms of the GRA Agreement and testified with respect to the outstanding issues. However, the GRA Agreement was only executed as of October 15, 2012 and was not filed with the Board until November 2, 2012.

4.0 SETTLEMENT AGREEMENT

4.1 The Board's approach to settlement agreements

[24] In its previous Decisions, the Board has set out the principles it applies in its consideration of settlement agreements. Those principles bear repeating. In its Decision dated November 5, 2008, the Board outlined its general approach to settlement agreements submitted to it for approval:

> [12] The Board's *Regulatory Rules* facilitate settlement discussions. The Board welcomes and appreciates the efforts of parties to, in good faith, settle issues, even where, as sometimes happens, a settlement cannot be ultimately achieved.
>
> [13] Where, as here, the Agreement is supported by representatives of all of the customer classes, the Board can have confidence that the Agreement is in the public interest.
>
> [14] Customers of NSPI and members of the public are, perhaps understandably, wary of the settlement process. Many of those customers and members of the public may not appreciate that by the time the hearing commences 80% of the rate hearing process has already happened. NSPI filed extensive evidence, as required by the Board, to support its rate request. Interested parties and Board Staff asked NSPI many hundreds of written questions (Information Requests), to which responses were filed.
>
> [15] All of the parties who chose to do so filed evidence, including expert evidence. Written questions (Information Requests) have been asked of and answered by interested parties who filed evidence. NSPI filed reply evidence. As noted, all of this happened before the hearing was scheduled to begin so that the parties and the Board are well informed about the case in advance of any oral public hearing.
>
> [16] The public can rest assured that the Board Members hearing the matter have also thoroughly reviewed all of the material in advance of coming to a decision as to whether to approve the Agreement as being in the public interest.
>
> [17] Settlement agreements, while relatively new in regulatory matters before the Board, are common in the litigation process. Within the Board's adjudicative mandate, for example, assessment appeals, planning appeals and other matters are often settled. In the civil courts of Nova Scotia, a much higher percentage of cases are settled than go to trial.
>
> [18] That is not to say that the Board would hesitate to reject a settlement agreement it did not consider to be in the public interest, however, it should be understood that a properly supported settlement is a success of the regulatory process, not a failure.
>
> [Decision, 2008 NSUARB 140]

4.2 The GRA Agreement in the present case

[25] The GRA Agreement addresses many outstanding issues between NSPI and most of its customers. However, several issues were not resolved, including the FAM audit, pension costs, LED street lighting and the underground storage of natural gas.

[26] Notably, the GRA Agreement adopts the two year RSP proposed by NSPI.

[27] The GRA Agreement reads as follows:

2013-2014 General Rate Application
Settlement Agreement
October 15, 2012

Whereas NS Power filed a General Rate Application for 2013 and 2014 on May 8, 2012;

And Whereas the Board Hearing Schedule provided for Information Requests to NS Power and Responses, Testimony from Board and Intervenor consultants with corresponding Information Requests and Responses, Reply Evidence from NS Power, and Opening Statements from parties and consultants;

And Whereas the Parties to this Settlement Agreement, which include NS Power, Avon Group, the Consumer Advocate and the Small Business Advocate, desire to resolve the General Rate Application by way of this Agreement;

The Parties agree:

1. The 2013-2014 Rate Stabilization Plan is accepted and adopted, as filed, subject to the changes contained in this document. This includes a three percent overall rate increase for each of 2013 and 2014, plus a deferral of forecasted revenue requirement that is not otherwise recovered by the two rate adjustments, using the August 31 update. The deferral recovery would begin in 2015 in an amount that is equivalent to the s.21 amount in rates.
2. NSPI will identify, at its own discretion, and manage the business in order to achieve a $27.5 million reduction in the deferral balance over the two year period. None of the reductions will be achieved through fuel forecast reductions. This will resolve all issues relating to revenue requirement, subject to items 3 and 6 (below).
3. ROE will be set at 9.0% for rate making purposes, with a 0.25 band. Therefore the ROE range will be from 8.75% to 9.25%.
4. The result of the changes in items 2 and 3 will be that the fixed cost deferral amount will not exceed $84.8 million, which includes the financial effect of the lower ROE and the resulting lower interest costs relating to financing a lower deferral amount. For the purpose of calculating interest, the deferral will be reduced by $13.75 million in each year of 2013 and 2014.
5. S.21 amounts will be accepted as filed. The S.21 AAA Mechanism will continue as part of the Rate Stabilization Plan, as proposed in the Application.
6. Fuel - Base Cost of Fuel will be set as per the August 31 update. Liberty's proposals regarding natural gas will be determined by the outcome of the FAM Audit process. If the UARB accepts Liberty's views in that process, the Base Cost of Fuel and therefore the revenue requirement (and deferral) will be reduced to the extent the audit outcome affects the fuel forecast for 2013 and 2014. Liberty's suggested

reductions relating to imports are not adopted but the suggestion will be referred to the Small Working Group for study and possible changes to the forecasting methodology for future implementation.

7. The FAM Audit issues will continue to be litigated in accordance with the Board schedule for the hearing that commences October 29. The financial result of the hearing, if any, will be implemented beginning January 1, 2013 separate and apart from the Rate Stabilization Plan.
8. NS Power's proposal to update OATT pricing, with the exception of its request for an ECRM (which has already been determined by the Board), will be accepted as filed. The matter of the MEUNSC responsibility for deferrals, in the event of departure from the system, may be determined in a future application before the UARB. Parties are free to take any position on OATT related matters in future proceedings.
9. The SBA request for an adjustment to the R/C ratios for small business classes and narrowing of the band (0.95 to 1.05) will be referred to the Cost of Service Study proceeding.
10. Adjustments will be made to the Large Industrial Interruptible class to ensure this class of customers receives the same 3% adjustments as experienced by other customer classes, similar to the approach taken in the 2009 GRA Settlement Agreement.
11. The Interruptible Rider to the Large Industrial Tariff will be revised as provided in the attached September 28, 2012 letter from NS Power to the UARB.
12. During the hearing parties to the agreement will refrain from seeking any changes to the agreement or additional reductions to revenue requirement. This settlement is without prejudice to any position that parties may take on these issues in future proceedings.

[Exhibit N-201]

[28] The GRA Agreement has an attachment related to the Interruptible Rider.

[29] In his Opening Statement at the hearing, Rob Bennett, NSPI's CEO, stated that the GRA Agreement, which incorporates the RSP, provides the Utility and its customers with the time to adjust to significant changes in NSPI's load and costs:

> The Rate Stabilization Plan provides the best approach to the complex challenges we face, together, with the Board and our customers. Input costs are rising, new renewable energy is being added to the system, and load is dropping – quickly and dramatically. Any of these challenges would create upward pressure on electricity rates; and we are experiencing them all at once.
>
> Mr. Chairman, we will continue to work on behalf of our customers to meet the challenges that will arise during this Rate Stabilization period. This agreement gives everyone time to adjust to the lost pulp and paper load, but does not solve that problem. In 2015 we will have to incorporate the lost load into general rates, including the final payment of the 2012 Fixed Cost Deferral, and any other changes in our cost structure that are forecast for that test year.

[NSPI Opening Statement, Exhibit N-123, p. 1]

[30] In NSPI's Closing Submission, counsel for the Company submitted:

> The Settlement Agreement reflects agreement by the parties to accept and adopt the Rate Stabilization Plan, as filed, subject to specific changes provided in the Settlement Agreement. That includes a net 3 percent overall increase in each of 2013 and 2014, with a deferral of forecast revenue requirement, based on the Company's August 31 Load and Fuel Update filing, not otherwise recovered by the 3 percent rate increases in each of the next two years. …
> Key to the settlement is the fact that it reflects a commitment by the Company to be responsible for $27.5 million of the original deferral of revenue requirement. The parties agreed that no deferral reductions will be made through fuel adjustments, but that the Company will identify at its own discretion, and manage the business in a manner that will achieve the $27.5 million deferral reduction. This commitment represents a significant challenge to the Company over the next two years, and will provide a substantial long term benefit to customers.
>
> [NSPI Closing Submission, November 23, 2012, p. 12]

[31] NSPI counsel also noted the benefits to customers of reducing the return on equity:

> …This includes the agreed reduction in NS Power's return on equity (ROE) for rate setting purposes from 9.2 percent to 9.0 percent along with a change to the earnings band to +/- 0.25 percent, making the earnings band 8.75 to 9.25 percent. This change also contributed to reductions to the Company's revenue requirement for 2013 and 2014, leading to further reductions made to the deferral amount, over and above the $27.5 million.
>
> [NSPI Closing Submission, November 23, 2012, p. 15]

[32] The CA supports the approval of the GRA Agreement. In his view, after analyzing all of the Pre-filed Evidence, the result was not likely to be better by pursuing a contested hearing:

> It is to be noted that the settlement agreement calls for a reduction in NSPI's requested revenue requirement. The Consumer Advocate and other signatories to the settlement agreement analyzed all of the pre-filed evidence and, with the benefit of assessments by expert consultants, concluded that rate increases proposed in the settlement agreement are reasonable and justified. Furthermore, it is the view of the Consumer Advocate and the settling intervenors that the agreed-upon reduction in revenue requirement was not likely to be improved through additional litigation. One important aspect of the proposed settlement agreement, as noted by Commissioner Dhillon in his questioning of the NSPI panel, is that the proposed increases are 3% class revenue increases. ...
>
> In addition to the rate increases in 2013 and 2014, the settlement agreement also provides for deferred collection of a significant portion of NSPI's revenue requirement. Although the Consumer Advocate continues to be leery of deferral mechanisms, there was an identified and important correlation between the deferral proposed in this settlement agreement and the extinguishment of the section 21 deferral which is presently in rates. The net effect is that the deferral contemplated in this settlement will

be collected once the section 21 deferral has been paid off and therefore represents an opportunity to smooth or even out rate increases experienced by customers.

[CA Closing Submissions, November 23, 2012, p. 4]

[33] The SBA also submitted that, after a review of the evidence, the GRA Agreement represented a reasonable resolution of most issues in the Application:

> The Settlement Agreement signed by the Consumer Advocate, the Avon Group, Nova Scotia Power and the SBA, was the result of much consultation and discussion and was not taken lightly. Accordingly, after assessing the Application and merits of achieving greater results by litigating before the Board, and after reviewing the experts' reports, asking numerous questions, followed by numerous hours of negotiations, the SBA was satisfied the Settlement Agreement dated October 15, 2012, represents a reasonable resolve with respect to many items referred to in the General Rate Application when compared with the uncertainty of successful litigation.

[SBA Closing Argument, November 23, 2012, pp. 1-2]

[34] Counsel for Avon noted that the GRA Agreement represents a resolution of issues between all customer classes, excluding municipal customers:

> In each case, Intervenors must carefully evaluate the evidence to judge the costs and risks of challenging the Utility's application against the advantage of a negotiated settlement. With the exception of the Municipal customers, the Settlement Agreement has the support of representatives of all customer classes who participated in the process - the Avon Group (Large Industrial), the Consumer Advocate (Residential) and the Small Business Advocate (Small General, General, Small Industrial), as well as NSPI. It is a reflection of the good faith efforts of the participants that a settlement was achieved in a very compressed time frame. There were compromises among all signatories but only time will tell whether it is a "good" deal for all concerned.

[Avon Final Submissions, November 23, 2012, para. 5]

[35] Counsel for Avon also highlighted a number of the elements of the GRA Agreement which will benefit customers:

> The Agreement results in an across-the-board 3% increase in each of 2013 and 2014 plus a deferral of forecasted revenue requirement not to exceed $84.8 million (clause 4). At the end of the two years, the deferral is planned to be recovered in an amount equal to the Section 21 payment that is already embedded in rates (clause 1). As part of the Settlement Agreement, NSPI has agreed to a $27.5 million reduction in the deferral balance spread equally over the two year period (clause 2). In addition, the ROE will be set at 9.0% plus or minus 25 basis points, i.e. 8.75% - 9.25% (clause 3). *The Settlement Agreement continues the previously agreed-upon cap on ROE through the s.21 AAA mechanism with any excess applied against the deferral (clause 5). This is an element of*

> *the negotiated Agreement that would not have been achieved through a contested proceeding*. [emphasis added]
>
> [Avon Final Submissions, November 23, 2012, para. 7]

[36] Moreover, Avon Counsel noted that the GRA Agreement contains two clauses which are particularly significant for large industrial interruptible customers, including a clause which provides that this class receives the same 3% increase in rates as other classes, together with revisions to the Interruptible Tariff Rider which balances the risk between NSPI and its interruptible customers respecting notices to reduce load.

[37] The Province does not oppose the settlement process and suggests that the proposed GRA Agreement is worthy of serious consideration by the Board:

> Although it is not a signatory to the Settlement Agreements filed in this case, the Department of Energy does not oppose the settlement process, as outlined and applied by the Board in its past decisions. In this case, the Settlement Agreement has been executed by representatives of almost all of NSPI's classes of customers and therefore we would respectfully suggest warrants serious consideration.
>
> [Province Closing Submissions, November 23, 2012, para. 12]

[38] The Province also noted that the GRA Agreement benefits customers. Counsel pointed out that the proposed $27.5 million non-fuel cost reduction in NSPI's deferral is not to be achieved through reductions in forecasted fuel costs. After noting the benefits of the RSP, as described immediately below in this Decision, counsel for the Province added:

> …At the same time, the revenue requirement reductions agreed to in the proposed settlement agreement will reduce the extent to which future rates are impacted as a result of the stabilization plan. These revenue requirement reductions include a lowering of NSPI's return on equity, which the Department of Energy applauds.
>
> [Province Closing Submissions, November 23, 2012, para. 13]

4.3 Rate Stabilization Plan

[39] A major component of the NSPI Application is the RSP. Subject to the changes noted in the GRA Agreement, the 2013-2014 RSP is adopted as part of the GRA Agreement.

[40] NSPI has forecast the revenue requirement for each of the next two years instead of the traditional single year approach. The elements of the RSP are set out in the NSPI Application:

> The Rate Stabilization Plan, which provides for recovery of the 2013 and 2014 revenue requirements is as follows:
>
> i. For each customer class, an average three percent increase on January 1, 2013 and an average three percent increase on January 1, 2014, after factoring in the 2010 FAM deferral reductions in 2013 and 2014,
>
> ii. Deferral of any portion of the Board approved revenue requirement not recovered by the average 3 percent annual increases. Effectively, this will continue the 2012 Fixed Cost Recovery deferral, which will continue to grow until the end of 2014, with recovery of the deferral over an 8 year period beginning in 2015,
>
> iii. FAM adjustments, other than for the 2010 FAM deferral reductions and the 2011 FAM imbalance both of which are reflected in the 2013 Balance Adjustment, will be deferred, to be incorporated into customer rates in 2015, and the FAM incentive will remain suspended until the end of 2014.
>
> [NSPI Application, Exhibit N-3(i), pp. 2-3]

[41] The 2012 Fixed Cost Recovery Deferral, which accommodated uncertainty about the province's pulp and paper load, was approved by the Board as part of NSPI's 2012 general rate application. In that proceeding, the settlement agreement approved by the Board initiated the Fixed Cost Recovery Deferral. The 2012 Fixed Cost Recovery Deferral was accepted by the same parties to the present GRA Agreement.

[42] NSPI's Application provided that the RSP deferral would be $130.7 million [Undertaking U-6]. Under the proposed GRA Agreement, the deferral will not exceed

$47.1 million at December 31, 2013 and will not exceed $84.8 million at December 31, 2014.

[43] NSPI's Application states that the amount of the deferral will be calculated separately for each class of customer, such that the "across-the-board 3-percent increase" will result in deferrals that accurately reflect the specific cost of serving each class of customer.

[44] Under the proposed RSP, the annual three percent adjustment will incorporate forecast decreases connected to the phase-out of the 2010 FAM Deferral. Also, the FAM will continue to operate, but additional AA and BA changes in 2013 and 2014 fuel costs will be deferred within the FAM until the RSP ends.

[45] NSPI submits that recovery of the deferral, commencing in 2015, will coincide with the end of the Section 21 Tax Deferral, which NSPI has been collecting from ratepayers over eight years ending in March 2015:

> In the current situation, NS Power believes a modest, short-term deferral of increased expenses is an appropriate way to stabilize rates for customers over the next two years. We propose to begin recovering the deferred costs in 2015, just as the Section 21 Tax Deferral expires. By timing the deferral this way, and if the deferred amount is less than $110 million, [NSPI] will be able to recover it in full over eight years, with no change in rates. In effect, as soon as [NSPI] finish[es] collecting the Section 21 Tax Deferral, [NSPI] will replace it with an eight-year recovery of the Fixed Cost Recovery deferral.
>
> [NSPI Application, Exhibit N-2, p. 28]

[46] Counsel for Avon also submits that the RSP benefits the members of the Avon Group by providing a "predictable measure of stability" over the next two years:

> From the perspective of the Avon Group, the Settlement Agreement results in a predictable measure of stability for the next two years and avoids the time, expense and uncertainty of a contested rate case. ... Members of the Avon Group shoulder their own regulatory costs, so the ability to predictably budget for energy costs over the next two years without the risks and costs of contested proceedings was attractive.
>
> [Avon Final Submissions, November 23, 2012, para. 6]

[47] Similar reasoning was expressed by the SBA:

> The SBA is further of the belief the two (2) year rate stabilization plan which calls for an overall average 3 percent rate increase for customer classes effective January 1, 2013, and further increase of 3 percent effective January 1, 2014, will help reduce litigation fatigue, and give stability for small business with respect to rate stabilizing increases for the next two (2) years. …
>
> [SBA Closing Argument, November 23, 2012, p. 2]

[48] Counsel for the Province refers to the RSP as a positive aspect of the GRA Agreement:

> From the Department of Energy's perspective, there are many positive aspects to the proposed Settlement Agreement. The acceptance and adoption of the 2013-2014 Rate Stabilization Plan, while not avoiding rate increases, will dampen the impact of those increases. At the same time, the revenue requirement reductions agreed to in the proposed settlement agreement will reduce the extent to which future rates are impacted as a result of the stabilization plan...
>
> [Province Closing Submissions, November 23, 2012, para. 13]

4.4 Findings

[49] The GRA Agreement represents a comprehensive resolution of many contested issues between NSPI and the Intervenors representing most of its customers. It addresses a number of significant components raised in the NSPI Application.

[50] The Board is mindful that the GRA Agreement represents a negotiated settlement by most represented customer classes, with the exception of the municipalities, whose involvement was directed to other issues in the GRA proceeding as described later in this Decision.

[51] In the Board's view, an important component which will benefit customers is the RSP, which limits across-the-board increases of 3% in each of 2013 and 2014, while deferring recovery of NSPI's remaining revenue requirement to 2015 when the Section 21 Tax Deferral will be fully retired. The net effect of the RSP is that the

revenue requirement deferral will only be collected after the Section 21 Tax Deferral has been retired. The deferral will be collected over an 8 year period beginning in 2015.

[52] Without the RSP, customers would have faced much larger rate increases, particularly in 2013. As noted by the CA, this will "smooth or even out rate increases experienced by customers". Counsel for Avon agreed that this will provide ratepayers with a "predictable measure of stability" over the next two years.

[53] In its original Application, NSPI had proposed that the deferral would be about $124.4 million (Exhibit N-3(i), Appendix P, Attachment 2), later amended to $130.7 million in Undertaking U-6. The GRA Agreement provides for a $27.5 million non-fuel cost reduction in NSPI's deferral. Accordingly, the deferral will not exceed $84.8 million at December 31, 2014, which includes additional adjustments made by NSPI in the hearing.

[54] The GRA Agreement also reduces NSPI's return on equity from 9.2% to 9.0%, along with a revised earnings band of 8.75 % to 9.25 %. This will also result in further reductions to NSPI's revenue requirement for 2013 and 2014, leading to further reductions made to the deferral amount, over and above the $27.5 million non-fuel cost reduction.

[55] Finally, as noted by counsel for Avon, the GRA Agreement continues the previously agreed-upon cap on return on equity through the s.21 AAA mechanism, with any excess applied against the deferral. This would not have been achieved through a contested proceeding.

[56] Taking into account the evidence and the submissions, the Board is satisfied that the GRA Agreement is in the public interest and that it should be

approved. In the view of the Board, the GRA Agreement provides for rates that are just and reasonable.

[57] The Board approves the NSPI Application, except as amended by the terms of the GRA Agreement or as otherwise varied in this Decision. Rates will increase by 3% for each customer class on January 1, in each of 2013 and 2014. The Board notes that it also approves the requested changes to Accounting Policy 5900 – Tax and the proposed updated OATT pricing.

[58] The Board directs NSPI to outline in 2013 and 2014 where it has applied the $27.5 million non-fuel cost reductions negotiated in the GRA Agreement. This disclosure is to accompany the year-end financial statements in the respective years.

5.0 PENSION COSTS

5.1 Regular Pension Plans

[59] In its Decision of November 28, 2011 (2011 NSUARB 184), the Board indicated that it would investigate the issue of pension costs in this proceeding.

[60] Peter Hayes, of Eckler Ltd., was retained by Board Counsel to examine NSPI's pension costs.

[61] Mr. Hayes noted that Company contributions to the NSPI pension plan have grown to be several multiples of what employees contribute. He goes on to say:

> In managing its pension costs, I believe NSPI faces serious impediments. These impediments are largely self-imposed, and to an extent cultural, but until they are removed it will be difficult for NSPI to gain control of its pension costs. In the meantime, these costs will continue to grow at a high level.
>
> [Exhibit N-59, p. 2]

[62] Among the impediments Mr. Hayes noted were:

a) A management focus on the performance of plan assets at the exclusion of more holistic plan management;

b) A lack of willingness to engage unionized employees in meaningful discussion around the reform of the pension;

c) Certain concerns raised in confidence about the governance structure.

[63] It appears to the Board that until very recently NSPI has done little, if anything, to address increasing pension costs. The Company witnesses cited constraints of the collective agreement with NSPI's Union and the recent influence on pension expense of the financial market losses as reasons for not doing so earlier.

[64] Among other recommendations Mr. Hayes suggested the test year revenue requirement should be set at a level which reflects higher employee contribution rates.

[65] NSPI was, in fact, engaged in collective agreement negotiations during the course of the hearing.

[66] NSPI confirmed to the Board that it had reached an agreement with the IBEW on the terms of a new collective agreement which was approved on November 5, 2012. In a letter dated November 16, 2012, NSPI outlined changes to the pension plan.

<u>Employee contributions</u>:

- Employee contributions to the DB Plan will change from the current level of 5.4% of pensionable earnings up to the Year's Maximum Pensionable Earnings ("YMPE") plus 7.0% of pensionable earnings in excess of the YMPE as follows:
  - Effective January 1, 2013, members will contribute 6.15% of pensionable earnings up to the YMPE and 8.00% of pensionable earnings in excess of the YMPE;
  - Effective January 1, 2014, members will contribute 6.90% of pensionable earnings up to the YMPE and 8.75% of pensionable earnings in excess of the YMPE; and

- o Effective January 1, 2015, members will contribute 7.40% of pensionable earnings up to the YMPE and 9.50% of pensionable earnings in excess of the YMPE.

Final Average Earnings definition:

- Effective January 1, 2013, the Final Average Earnings definition will change from the "best average four years" to the "best average five years".

[67] The Board sees these changes as a significant step in pension reform. The Board accepts these changes as adequate initial steps.

[68] NSPI, in its Final Submission, submitted that the changes that had been recently negotiated to the pension plan should be considered as part and parcel of NSPI's effort to reduce expenses by the $27.5 million agreed to in the GRA Agreement. Clearly contract negotiations were well advanced when NSPI agreed to the GRA Agreement and the Board accepts that there does not need to be a further adjustment to the revenue requirement to reflect these changes that were achieved through negotiation.

[69] In future years these costs savings will be embedded in the revenue requirement asked of customers.

[70] The Board, however, expects NSPI in future to take additional steps to improve contributions to, and the funding of, the pension plan.

5.2 Supplemental Executive Retirement Plan

[71] Two issues arose in the course of the hearing with respect to NSPI's Supplemental Executive Retirement Plan (SERP). This plan is available to employees who earn more than approximately $150,000 per year.

[72] Such plans are not unusual; indeed the Province of Nova Scotia provides a SERP plan for certain of its employees who earn above the pensionable payout limits permitted by the Canada Revenue Agency.

[73] The first issue is that NSPI secures this pension by purchasing a letter of credit. The letter of credit is, in part, to secure the pension plan in the event NSPI was to discontinue operations and therefore be unable to fund this obligation.

[74] The other issue is that the eligible employees of NSPI do not make any contribution towards these additional benefits. In other words, the Company, using funds paid by ratepayers, is funding 100% of this pension plan.

[75] Contrast that with the Province of Nova Scotia where employees eligible for the Province's SERP fund 50% of the contributions to the SERP with the employer paying the other 50%.

[76] With respect to the letter of credit, it appears to the Board that the letter of credit places the senior executives at NSPI in a more secure position than any other employee in the Company with respect to their pension entitlement. The NSPI employee pension plan is not secured by a letter of credit. NSPI is a regulated monopoly in the Province of Nova Scotia. The chance of NSPI going out of business is extremely remote.

[77] In the Board's view, payment for that portion of the letter of credit that secures the SERP is an unnecessary expense and is not an expense that should be borne by ratepayers. Accordingly, the Board disallows that amount from the revenue requirement.

[78] With respect to the SERP, the Board considers it unreasonable that the most highly paid employees working for NSPI make no contribution to the supplemental pension plan.

[79] NSPI is free to continue to provide that benefit. However, the Board directs that in the test years and in future NSPI must adjust the revenue requirement to deduct an amount from the SERP pension payments to reflect a deemed employee contribution to the SERP, on the assumption that the employee had contributed 50% to the pension plan and the employer 50%. In the test years, the Board, based on projected benefit payments identified in Exhibit N-3(v), believes the amount to be disallowed is $2.05 million in 2013 and $2.2 million in 2014.

[80] NSPI can discuss with Board Counsel the most tax efficient way of implementing this direction from the Board.

[81] These deductions and the letter of credit deduction are in addition to the $27.5 million provided for in the GRA Agreement.

6.0 EXECUTIVE COMPENSATION

[82] The Legislature has passed amendments to the *Public Utilities Act* limiting the amount of remuneration, bonuses and other benefits that can be recovered from rates with respect to compensation of executive employees of NSPI.

[83] By regulation, the remuneration amounts are governed by amounts contained in the Province of Nova Scotia's Senior Officials Pay Plan.

[84] The Board assumes that pension payments on behalf of executives would reflect only amounts of salary permitted by the *Act*.

[85] In its Compliance Filing, NSPI is to reduce its revenue requirement to reflect the changes as a consequence of this legislation. This reduction is in addition to the $27.5 million agreed to as part of the GRA Agreement.

7.0 LED STREETLIGHTING

7.1 Evidence

[86] The *Energy-efficient Appliance Regulations* were amended by the Province on September 10, 2012, requiring all NSPI owned streetlights to be of the LED type after December 31, 2019. NSPI proposed to implement this change over a number of years as a part of its Annual Capital Expenditure plan. The cost of this changeover is the responsibility of the municipalities based on the number of streetlights in each jurisdiction. The Union of Nova Scotia Municipalities ("UNSM"), which represents all municipalities in the Province, is objecting to the cost which NSPI plans to pass on to the municipalities.

[87] NSPI proposes to defer a decision on the LED streetlight stranded cost to a later date, stating it plans to file a capital work order with the Board:

> …As explained in Appendix I of this Evidence, NS Power proposes to treat the non depreciated net book value of these streetlight fixtures as a stranded cost that constitutes a regulatory asset. We propose to defer the amortization of this asset until the Board approves the recovery of this cost through the implementation of appropriate LED streetlight conversion charges. This will happen in concert with the Capital Work Order Application for the LED streetlight conversion program. We propose to recover the capital carrying costs associated with this regulatory asset from the full service LED streetlight customers.
>
> [Exhibit N-2, p. 130]

[88] In Appendix I of its Application, NSPI provided a *Cost of Service and Pricing Study for Unmetered Services* which included streetlights and other services such as traffic lights, ornamental streetlights, crosswalk lights, etc. The report provided

details of NSPI's proposed rate making methodology and calculations of streetlight rates.

[89] The UNSM, in its Pre-filed Evidence, noted that municipalities are struggling to provide normal services and an additional $100 million for LED streetlights conversion is a significant burden. The UNSM has concerns with the cost of stranded assets and time allowed for conversion of these streetlights. The UNSM's understanding is that as a part of the 2012 GRA Settlement Agreement, the net book value of stranded streetlights is $12 million and is supposed to decline over time as only LED streetlights are installed/replaced after 2011. The UNSM also noted inconsistencies when NSPI deals with the municipalities in billing and stranded asset fees for streetlights.

[90] HRM, in its Pre-filed Evidence, noted its concerns with NSPI overcharging municipalities. HRM noted its concern with respect to the total charge for streetlights. It stated that NSPI's maintenance and capital charges do not align with the actual cost for these services. HRM also disagreed with NSPI that the energy component is being subsidized by the other components of the total streetlight charge.

[91] HRM further noted that NSPI's evidence over time has been inconsistent and difficult to follow:

> On the rate setting front, the LED street light conversion has exposed some of the long standing issues with respect to the lack of accounting detail in the unmetered Cost of Service. It appears NSPI has made it extremely complex to use cost of service accounting principles for a simple street light because it has not tracked the age or quantity of lights properly. The process has become very onerous, non-transparent and inefficient. Clearly NSPI has had significant challenges in determining unmetered rates over a protracted period.
>
> [Exhibit N-54, p. 7]

[92] HRM agreed with UNSM that the issues in dispute are the stranded cost and phase-in time for LED streetlights conversion. HRM noted that its understanding of the 2012 GRA settlement is different from NSPI's understanding.

[93] Albert Dominie, a consultant for HRM, noted problems with the current pool of assets in the streetlights category. This includes types, quantity and how the stranded costs are allocated between streetlights and other assets in the pool.

[94] Mr. Dominie questioned the use of the Bank of Canada Inflation Calculator to determine the net book value of retired streetlights. He recommended the use of the Handy-Whitman Index of Public Utility Construction Costs which is also used by the Federal Energy Regulatory Commission. He explained that the Bank of Canada Inflation Calculator provides a higher actual installed cost than the Handy-Whitman Index.

[95] Mr. Dominie does not agree with NSPI's method to calculate the stranded cost of current streetlights. He proposed a true up and reconciliation process during the LED streetlights conversion by carrying out a physical survey of each streetlight to determine actual life based on the date stamp.

[96] NSPI, in its Reply Evidence, noted that the net book value of streetlights has been approved by the Board in past applications, including the depreciation hearings and it is entitled to recover these costs from its customers. It disagrees with the use of the Handy-Whitman index method and field survey proposal by Mr. Dominie.

[97] NSPI outlined the process it has followed to calculate the stranded cost of streetlights:

> NS Power's approach with regards to calculating a stranded asset pool is simple and has not changed. That is, the net book value of the assets is the unrecovered investment. To determine per unit value, NS Power has proposed dividing the asset pool by the number

> of lights billed in the Customer Information System. NS Power has repeatedly stated through the 2013 & 2014 GRA application that the rates should be set with the capital work order process consistent with the 2012 Settlement Agreement. In an effort to be helpful, NS Power has provided information over the last couple of years. In fact, draft regulations were only issued April 25th, 2012.
>
> [NSPI Reply Evidence, Exhibit N-106, pp. 96-97]

[98] The Board and HRM during the hearing requested clarification on the type of streetlights being replaced after the 2012 GRA Settlement Agreement approved by the Board in the 2012 GRA. That Settlement Agreement required NSPI to install only LED streetlights when replacing the old streetlights. NSPI responded:

> …So we've been continuing on using materials that were already in inventory, not buying -- not in any way, shouldn't be characterized as spending more than we should have. We're just fixing the lights that people call in and say are broken.
>
> [Transcript, September 19, 2012, p. 547]

7.2 Findings

[99] The Board has considered the evidence filed and issues raised by the UNSM, HRM and NSPI. NSPI proposed that the matter of LED streetlights be deferred to a later date when it intends to file a capital work order with the Board. HRM does not have a problem with this approach except the amount of net book value of current streetlights which NSPI plans to use in its work order.

[100] NSPI proposed to use the current net book value of streetlights (estimated at $23 million) based on methods and records it has used in the past including depreciation hearings. However, HRM argued that the net book value NSPI proposes to use is not correct and should be $12 million as noted in the 2012 GRA Settlement Agreement. HRM further stated that this amount is to be confirmed by actual survey of all current streetlights, which will also determine the number and age of streetlights.

HRM also raised the issue of non-streetlight assets being in the streetlight class and whether some of the current net book value belongs to these other assets.

[101] The Board agrees that dealing with the streetlight issue as a part of a capital work order is a reasonable approach, with the exception of the net book value question. The net book value of streetlights has been calculated under the current method for a long time and any change in the net book value now would be unfair to other ratepayers. The current method has been approved in prior depreciation Decisions of the Board. The net book value amount is the responsibility of the streetlight class and any reduction in this amount would shift the responsibility to other customer classes. The Board does not agree with HRM's proposal to change the net book value of streetlights currently included in the NSPI rate base. How this amount is shared between municipalities is something NSPI should work out with them.

[102] The Board denies HRM's request to recalculate the net book value of streetlights.

[103] The second issue raised by HRM is the type of replacement streetlights used by NSPI since the Board's 2012 GRA Decision [2011 NSUARB 184]. It is the Board's understanding of the 2012 Settlement Agreement that NSPI was to use only LED streetlights when replacing the current streetlights. NSPI has stated that it has only used non-LED streetlights which were in its inventory.

[104] In the circumstances, if the non-LED streetlights were already in inventory, the Board finds this to be an acceptable approach. However, NSPI should have clarified the use of inventory with Intervenors during the 2012 GRA settlement discussions.

[105] The Board is not certain, based on the evidence, if NSPI has purchased new non-LED streetlights after the 2012 GRA Board Decision.

[106] The Board orders NSPI to confirm by February 28, 2013 that no new non-LED streetlights were ordered or purchased after the Board's 2012 GRA Decision.

8.0 LOW INCOME RESIDENTIAL CUSTOMERS

8.1 Submissions

[107] At the request of the CA item 15 was added to the Final Issues List, "Matters Related to Low Income Residential Ratepayers".

[108] The Affordable Energy Coalition, the CA and NSPI tabled a Settlement Agreement which the CA described as an agreement which addresses many long-standing issues faced by low income customers. Essentially the Agreement sets up a consultative process "with a view to resolving bill payment, credit and collection matters affecting low income residential customers". The text of the Agreement is as follows:

> The following provisions are requested to be included in final Order of the NSUARB in GRA 2013 NSUARB-NSPI-P-893 - Matter M-04972 with the consent of NSPI, the Consumer Advocate, and the Affordable Energy Coalition.
>
> Residential Low Income Issues
>
> 1. NSPI, the Affordable Energy Coalition and the Consumer Advocate, shall seek an adjournment of the hearing on the matters identified in paragraph 4 of this joint proposal in this proceeding, in order to engage in a consultative process with a view to resolving bill payment, credit and collections matters affecting low income residential consumers, and the parties reserve the right to contest any of the evidence filed with the NSUARB in this proceeding, as may be appropriate, at a future hearing.
>
> 2. The consultative process shall be non-binding and without prejudice to either side to request the matters be brought back before the NSUARB to resolve any issue in relation to Board regulations or other matters and the parties agree to the appointment of a facilitator by the NSUARB on an as-needed basis.
>
> 3. The consultative process may solicit input from other social service agencies, non-governmental organizations involved in low income energy issues, as well as other resources and supports, as agreed to by the parties.
>
> 4. The items to be discussed by the parties are:
>
> a. Development of a Low-income Customer Charter;
>
> b. Changes to NSPI policy regarding deposits and payment agreements;

c. Development of joint recommendations, where appropriate, with respect to regulatory reforms, including with regard to deposits, payment agreements, interest charges and other miscellaneous charges, disconnection procedures, and requirements for the residential budget plan as they affect low income residential consumers;

d. Any other matters as agreed to by the parties.

5. The parties shall meet on a regular basis, at a minimum once every two months. The parties shall agree on a timetable, which shall reflect the following:

a. The first meeting shall take place not later than November 1, 2012;

b. The parties shall report back regarding the status of the consultation, with any agreements reached by the parties, and to the extent that agreement is not reached, request a further appearance and hearing before the NSUARB not later than June 30, 2013, and the evidence filed on behalf of the AEC in this proceeding shall form part of the evidence at that hearing;

c. NSPI shall provide a proposal regarding items (b) and (c) to the Affordable Energy Coalition and the Consumer Advocate one week in advance of the first meeting;

d. NSPI shall provide the results of its research with respect to regulatory differences in other jurisdictions to the Affordable Energy Coalition and the Consumer Advocate not later than December 1, 2012.

[Exhibit N-116]

[109] The Board approves the Agreement which will be appended as a Schedule to the Compliance Order and acknowledges, with appreciation, the work of the Affordable Energy Coalition, NSPI and the CA in moving this initiative forward.

[110] The Board receives literally hundreds of letters and emails a year from consumers who are struggling to pay their power bills and at the same time manage the cost of home heating, medication, groceries, etc. There is only so much the regulatory system can do to respond to these concerns but this Settlement Agreement is a welcome development.

9.0 COST OF SERVICE – BIOMASS

[111] NSPI has recently constructed a 60 MW biomass plant at Point Tupper, Nova Scotia. For purposes of rate base NSPI has determined the biomass plant is being added for environmental purposes only and should be classified totally as energy.

With respect to OM&G costs, however, the classification is the same as for all other steam plants, a portion of which is classified to demand, and a portion that is classified as energy.

[112] Mel Whalen, a witness on behalf of Board Counsel, recommended that until a more complete assessment is done as part of the upcoming cost of service review, NSPI should classify the biomass plant on the basis of system load factor, the same as other thermal plants, for the following reasons:

> a) Biomass is a steam plant.
> b) Biomass makes a contribution to capacity.
> c) The biomass plant was justified in part on the grounds that it would provide firm, dispatchable power and alleviate some of the concerns with respect to adding only non-dispatchable renewable resources.
> d) Classifying the biomass as other steam plants are classified is consistent with NSPI's classification of the biomass OM&G as all other steam OM&G is classified.
>
> [Exhibit N-42, p. 10]

[113] NSPI, in its Reply Evidence, says that even though the biomass generation is firm and is dispatchable, it considers the capacity related aspects of this plant to be of secondary importance to that of RES compliance. NSPI says classifying the asset on the basis of system load factor would mean there would be no distinction between this project and ordinary fossil fuel baseload generation.

[114] The Board notes that recent *Regulations* passed by the Province of Nova Scotia require that this plant, as opposed to being dispatchable, is essentially must-run.

[115] The Board agrees with Mr. Whalen that the characteristics of this plant are similar to any other steam plant. It makes a contribution to capacity and provides firm power, meaning that it should be classified on the basis of system load factor and

directs NSPI to do so. This issue may be reviewed in the upcoming cost of service proceeding.

10.0 NATURAL GAS STORAGE

10.1 Evidence

[116] Alton, in its Pre-filed Evidence, stated that the New England and Maritime market currently does not have a natural gas storage facility which can provide security of supply and manage the price of natural gas used by NSPI. The natural gas prices in this region have been volatile and NSPI can benefit from the use of a storage facility given the amount of natural gas used, which Alton estimates to be $110 million annually.

[117] Alton retained Gregory W. Hopper of Black & Veatch who, in his Pre-filed Evidence, provided analysis of the Maritime and New England natural gas market and price behavior. He noted that the lack of a natural gas supply in the region could make natural gas prices rise even higher and also increase volatility.

[118] Alton also retained Jan van Egteren of Anthem Economic Consulting Inc. who, in his Pre-filed Evidence, outlined various hedges used by NSPI to reduce gas price volatility. The hedges currently used by NSPI are financial, physical and geographic hedges. He then calculated the savings NSPI could achieve by using the natural gas storage facility by buying when the prices are low and using when prices are high. He noted that there is a possibility of additional savings in case of a “basis blowout” similar to what happened in December 2010.

[119] Alton proposes to construct a natural gas storage facility off the Halifax lateral to supply gas to Tufts Cove generating station. The proposed storage facility is

being designed to store a minimum of 4 BCF of natural gas at a maximum pressure of 2,028 pounds per square inch gauge ("psig") and a minimum operating pressure of 418 psig. The storage facility can also be used in the integration of intermittent renewable energy generation such as wind energy.

[120] NSPI, in its Reply Evidence, argued that this proceeding is not the place to discuss this issue which, in future, could be the subject of negotiations between Alton and NSPI. NSPI questioned the commissioning of the storage facility, which has an expected in-service date of April 1, 2015.

[121] NSPI disagreed with the benefits noted by Alton because in its opinion Alton has not considered certain items in its calculations to determine the cost savings.

[122] In response to Alton counsel's question on the use of natural gas storage facility, NSPI explained:

> MR. SIDEBOTTOM: I think storage can play an important part in the portfolio. The question to be asked is when is it the right time to enter into an agreement to secure storage? To date, it hasn't been the right choice for us and our customers. There could be a point in the future when it is the right time to secure some storage. So it's very much dependent on what's going on at a point in time.
>
> If gas sources were not as reliable there is an advantage to natural gas storage. Whether it completely justifies itself today or from some future date really is dependent on what your market circumstances are.
>
> [Transcript, September 18, 2012, p. 164]

[123] NSPI further stated that:

> MR. SIDEBOTTOM: To be partners with a potential supplier of that and have them be intimately knowledgeable of the value proposition to customers puts me or us in a compromised position in negotiating effectively the best overall cost to customers.
>
> I believe we will be looking at natural gas storage and studying that in the coming year when we have more information on wind integration. But Nova Scotia Power is happy to do that at its own cost. And we would see that it is difficult to be in a co-authored study with a potential recipient of the contract at the end of the day.
>
> [Transcript, September 18, 2012, p. 183]
>
> …

> All we're trying to say here is that we think it's appropriate to study the viability of natural gas storage. We think it's appropriate for it to be done on an impartial basis, not including the people who potentially propose to provide the storage.
>
> [Transcript, September 18, 2012, p. 193]

[124] In its Closing Submission, NSPI objected to Alton's request to order that NSPI be part of the study because this issue is not on the Board's Final Issues List for this hearing. NSPI stated that, if approved, other parties doing business with NSPI may view the GRA as a forum to advance their interest.

10.2 Findings

[125] Alton requested the Board order NSPI to participate in a natural gas storage study being carried out by Alton and Heritage Gas. NSPI objected to this request as this item is not on the Board's Final Issues List and also may interfere in its ability to minimize fuel cost and achieve a cost effective alternative for fuel purchases.

[126] Alton argued that NSPI's fuel cost can be reduced by the use of a gas storage facility.

[127] The Board understands that the use of gas storage is a type of hedge against higher gas prices in the future. Similar to other hedges, for the gas storage to be cost effective, there are many factors and assumptions one has to make so that the cost of the hedge is beneficial to ratepayers. These include the amount of gas, price of other fuels, and the cost of storage, to note a few.

[128] NSPI purchases fuel in conformance with its Fuel Manual developed over time with input from its stakeholders. The purpose of the Fuel Manual is to reduce cost and to secure a reliable fuel supply. NSPI actions in the purchase and management of fuel are audited every two years for prudency. Directing NSPI to purchase a certain

type of fuel or follow certain procurement procedures in advance of the audit may compromise the Board's ability to make a fair judgment on the audit findings.

[129] During the hearing NSPI agreed that gas storage does have benefits, but disagreed with Alton that now is the time to enter into a long-term gas storage commitment. NSPI intends to do its own study later in 2013 after the IRP update planned for 2013. NSPI's customer load has changed substantially due to the reduction in electricity demand caused by reduction in two paper mills' production volumes in the Province. The matter is further complicated by the *Renewable Electricity Regulations* requirements. The proposed IRP update is expected to provide directions on the amount and type of generation required to keep customer cost to a minimum and also meet renewable energy targets.

[130] The Board's intention is not to micromanage NSPI. Its management needs flexibility in its operations if it is to be judged on the prudency of its actions.

[131] The Board denies Alton's request to order NSPI's participation in a natural gas study with Alton and Heritage Gas.

11.0 FAM AUDIT

11.1 Introduction

[132] It should be noted that much of the evidence regarding the FAM Audit was filed in confidence and discussed during confidential sessions of the hearing. Accordingly, the Board is only in a position to provide an overview of the evidence and a summary of its findings.

[133] The FAM has generally been described as a mechanism that allows periodic adjustments to customer rates, outside general rate proceedings, to reflect

increases and decreases in the Utility's cost of fuel, provided they are prudently incurred.

[134] In its Rate Decision dated February 5, 2007, the Board identified at least four prerequisites prior to the implementation of a FAM:

> [45] For the guidance of the parties, however, and without in any way prejudging the issue, in the Board's view there are several prerequisites that must be in place in order for the Board to consider the adoption of a FAM now or in the future:
>
> 1. an adequate and appropriate fuel procurement policy at NSPI in which the Board has confidence;
>
> 2. timely disclosure of complete and adequate information by NSPI so as to ensure confidence that the procurement policy is being appropriately administered;
>
> 3. disclosure and transparency with respect to the administration of the FAM;
>
> 4. a meaningful audit process under the administration of the Board.
>
> [46] This list is not meant to be exhaustive.
>
> [Decision, 2007 NSUARB 8, paras. 45-46]

[135] In its GRA Decision dated November 5, 2008 the Board approved the FAM to take effect on January 1, 2009, conditional on the final approval of the Tariff and POA. A revised Tariff and POA were received on November 26, 2008 and approved by the Board in a letter dated December 11, 2008.

[136] Section 5 of the POA addresses the audit requirements and excerpts are included below:

> **5.0 AUDIT AND OVERSIGHT**
>
> The amounts charged through the FAM shall be subject to periodic audit to assure completeness and accuracy and to assure fuel and purchased power costs were incurred reasonably and prudently. The results of any audit shall form part of the issues for consideration by the Board in a subsequent FAM proceeding to consider the re-setting of the Base Cost of Fuel, or setting of the Fuel Adjustment Factor, or a General Rate Case at the request of NSPI or any interested stakeholder or upon Board order. Following consideration of the audit in any such hearing, the Board may make such adjustments (with interest if

appropriate) to existing balances or to already recovered amounts as it may find necessary.

Audit Process

The Board shall provide for the conduct of a Fuel Adjustment Mechanism (FAM) audit every second year. The Board shall have a qualified independent firm conduct the audit. The audit will address the financial and management/performance aspects of NSPI's fuel procurement and recovery under the FAM. The audit will include the FAM Formula, actual fuel and purchased power costs, contracts and management performance that affect the audit period from January 1, 20XX to December 31, 20XX+1. The first audit period will be for the year 2009. Subsequent audits will cover two-year periods.

Objectives and Scope of the Audit

The overall objective of the FAM audit will be to examine operational and managerial aspects of the fuel and energy procurement, management, and production functions and activities of NSPI, including any fuel or energy related affiliate transactions that involve these functions and activities directly or indirectly. The review will address adherence to good utility practice and consistency with the policies and procedures governing NSPI's procurement as described in the NSPI Fuel Manual.

The Scope of the Audit will include a review of fuel and energy procurement, fuel management, and generation production …

…

Prior to setting the final audit scope, the auditor shall meet with NSPI and interested stakeholders.

Timing of the Audit

The first audit will commence on February 1, 2010, and subsequent audits are expected to commence in February of every second year. The final report for the first audit will be filed with the Board and Stakeholders by July 2, 2010. Final reports for subsequent audits will be filed by July 2 of every second year. The final report will evolve from a draft report which is provided to NSPI and the Board within 30 days of the filing of the final report. The draft report should contain functional area task reports, a management summary, and include findings of operating effectiveness and efficiency, as well as any recommendations for adjustments in costs or changes in functions and activities.

[FAM POA, August 13, 2010, pp. 13-15]

[137] It should be noted that the original POA anticipated that the first audit would cover 2009 and 2010 and that the draft report would be provided to NSPI and the Board "forty-five days before the final report is filed". During 2010, following stakeholder engagement, NSPI requested Board approval of certain changes to section 5 of the

POA. Specifically, those changes included recognition that the first audit covered only 2009 and also a revision to the audit timing to state that the draft report will be provided to NSPI and the Board "within 30 days of the filing of the final report". Those changes were approved in the Board's letter dated October 12, 2010.

[138] As noted above, the first FAM Audit was conducted in 2010 and covered the 2009 calendar year. The Liberty Audit Report, which was filed with the Board on July 2, 2010, presented Liberty's findings, conclusions, and recommendations in eleven chapters, each of which comprised a principal area of examination and review. A total of thirty-one recommendations were included in Liberty's Audit Report.

[139] The 2010 Audit Report was included as an exhibit in the proceeding to set the Base Cost of Fuel ("BCF") for 2011. On page 12 of its evidence filing in the 2011 BCF proceeding, NSPI stated:

> The Company generally agrees with most of the recommendations of the Report. There are recommendations that require additional context or currently have alternative solutions that the Company has carried out or is in the process of implementing. NSPI suggests that the FAM can continue to provide an effective forum for dialogue about the conclusions and recommendations of the Audit Report.
>
> [Decision, 2010 NSUARB 219, p.12]

[140] NSPI's response to that Audit report was contained in Appendix C of its evidence Exhibit N-10 which outlined agreement and/or comments regarding each of the recommendations.

[141] As directed by the Board, NSPI filed its FAM Audit Recommendation Action Plan on December 9, 2010. Following subsequent discussions between NSPI and Liberty, a report dated June 9, 2011 was filed by Liberty which noted that NSPI had established acceptable action plans for 25 of the 31 recommendations. Some of the

outstanding issues were resolved, but others remained and were carried over to the 2012 FAM Audit.

[142] It bears repeating that in approving the FAM in 2007, the Board highlighted the importance of transparency and timely disclosure in its approval of the FAM:

> [59] NSPI now indicates it is committed to transparency and timely disclosure.
>
> [60] The Board wishes to make it clear to NSPI that if full and timely disclosure of complete and adequate information to assess its fuel procurement practices continues to be a problem, the implementation of a FAM will not occur...
>
> [Decision, 2007 NSUARB 174]

11.2 Prudency Test

[143] In 2005 NSUARB 27 (NSPI - P-881), the Board adopted the definition of prudence as set out in a decision of the Illinois Commerce Commission as a reasonable test to be applied in Nova Scotia.

[144] That test was set out at paragraph 84 of the Board's Decision:

> The standard for determining prudency of a utility's fuel procurement practices is well established. As stated by the Illinois Commerce Commission, "prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made….Hindsight is not applied in assessing prudence….A utility's decision is prudent if it was within the range of decisions reasonable persons might have made. … The prudence standard recognizes that reasonable persons can have honest differences of opinion without one or the other necessarily being imprudent.
>
> [Decision, 2005 NSUARB 27, para. 84]

[145] The Board went on to say:

> [89] While the Board recognizes that the definition of imprudence varies somewhat among the jurisdictions cited, there are several fundamental principles which are common. These include:
>
> - Were the utility's decisions reasonable in the context of information which was known (or should have been known) at the time?
> - Did the utility act in a reasonable manner and use a reasonable standard of care in its decision-making process?

- The imprudency test should relate to the circumstances at the time in question and not to hindsight.

[Decision, 2005 NSUARB 27, para. 89]

[146] NSPI, in its Closing Submission in the present matter, confirmed that from its perspective this is the test the Board should apply.

11.3 Lingan Derates

11.3.1 Evidence

[147] Liberty recommended a disallowance with respect to derates which occurred at the Lingan generating plant in December 2010. Derates occur when an operator must reduce, for one or more of a variety of reasons, the anticipated level of plant output.

[148] In its FAM Reply Evidence, Liberty described the risks known to NSPI in July and August 2010, when it re-introduced the local Prince coal, after the Province relaxed the mercury limits:

> The specific quality aspects of concern for the reintroduced local supply were ash, sulphur, and Btu content. Resuming its use in the Lingan fuel blend caused July and August results that failed to meet NS Power's own recognized guideline for identifying opacity risks. The operative metric was maintaining or exceeding a 1,000 parts per million concentration of SO_2 in unit stacks. Following the reintroduction of local supply, those concentrations fell well below the minimum guideline, ...
>
> Moreover, variability in the quality of reintroduced local supply and problems in its conformity to contract specifications were known issues. The coal's Btu content fell below minimum specification in January, July, and August 2010. Ash content was at the upper limit of specification in January, was well above the limit in July, and remained at the upper limit in August. ... Experience in January 2010 (after which NS Power discontinued use), and July 2010 (when NS Power resumed use) demonstrated, particularly in light of concern about stack SO_2 levels, that what was impossible to predict was that the coal blend, including reintroduced local supply, would sustain the ability to meet opacity limits without curtailing generation...
>
> [Liberty FAM Reply Evidence, Exhibit N-170, PDF pp. 110-111]

[149] In Liberty's opinion, NSPI was imprudent in that it did not appropriately address coal quality issues in July/August 2010 when there were signs that there were substantial risks of failure to meet opacity limits.

[150] While Liberty was mindful that NSPI was running the plant aggressively close to the limits, it stated that NSPI should have planned its coal burns to avoid the potential for problems, especially when Prince coal exhibited quality issues in July/August 2010.

[151] It bears repeating that some of the relevant evidence related to the Lingan derates in the FAM Audit was filed in confidence and discussed during confidential sessions of the hearing. Therefore, the Board is only in a position to provide an overview of the evidence and a summary of its findings.

[152] Some background on the importance of coal blends will be helpful to the reader.

[153] The Lingan generating facility was designed to operate at optimum efficiency while burning coal having specific characteristics. The primary fuel that the plant was originally designed to use was high sulphur coal that was available from the local mines in Cape Breton. Over the years, availability of that coal decreased while, at the same time, federal and provincial environmental regulations mandated reduced emission levels from generating stations burning fossil fuels.

[154] NSPI has regularly blended high sulphur domestic coal with low sulphur imported coal in order to optimize compliance with overall utility sulphur emission restrictions. It has also used mid-sulphur imported coal in its blend.

[155] In order to satisfy opacity limits and reduce emission levels, electrostatic precipitators are used at Lingan along with varying combinations of coal blends. Coals with various levels of sulphur, ash, moisture, and Btu are included in the blends. Changing the type of coal being burned can also change the efficiency of the plant. For example, burning coal that has a higher Btu content essentially means that higher levels of energy output can be obtained, while burning less fuel and producing lower overall emissions. However, this must be balanced against the design parameters of the generating facility and the effects of other fuels and chemicals in the fuel mix.

[156] Typically, the higher quality coals, in terms of lower sulphur, ash, moisture and higher Btu, are more expensive. Thus, coal blends must be carefully planned in order to maximize output at the lowest possible cost, while not exceeding emission limits.

[157] Further, government regulations which mandated a reduction in the mercury levels being emitted from the stacks required additional equipment and operational changes. This included altering fuel blends to reduce the mercury content and installing mercury abatement equipment along with chemical additives, such as powder activated carbon, to capture the mercury in the stack emissions. This abatement equipment and the powder activated carbon were designed to perform well with lower sulphur levels, but its use with higher sulphur coal can result in reduced performance.

[158] As of July 2010, the Province relaxed the targeted levels for mercury emission. This change identified graduated levels of mercury reduction, which also extended the compliance timeframe for achieving the revised emission target. As a

result of this, NSPI was able to use larger quantities of high sulphur, high mercury, domestic coal from the local Prince mine. Prince coal was available at a lower cost than imported coal. One of the benefits of burning this higher sulphur coal is that it improved precipitator performance so that derates due to exceeding stack opacity limits were less likely to occur.

[159] Along with managing the levels of sulphur dioxide and mercury emissions, NSPI needs to manage nitrogen oxide emissions, greenhouse gas emissions, and to ensure that the opacity of the stack emissions does not exceed the acceptable level specified in the operating permit. Clearly, a process of balancing fuel blends and chemical additives is needed in order to satisfy emission restrictions, while still maintaining efficient plant operation, maximizing energy output levels, and minimizing costs.

[160] In its Audit Report regarding derates at Lingan, Liberty stated:

> NSPI experienced the derates because the station precipitators were operating at the margin of performance, and could not tolerate any changes in coal quality, coal flow rates, or additional moisture in the coal. When above normal amounts of rain were experienced in December 2010, the station had no choice but to derate in order to comply with stack opacity limits. If NSPI had taken action to make the appropriate alternative coals [i.e., blends], there would have been the necessary margin in stack performance to have continued operation at normal power levels without derating. …
>
> [Liberty FAM Audit Report, Exhibit N-171, p. IV-28]

[161] In response, NSPI stated that the derates were caused by an uncharacteristically high amount of rainfall in December 2010. In its view, the 1 in 30 year rainfall event increased the moisture level in the coal (which is typically stored outdoors), which, in turn, reduced the MW output of the plant because it reduced the mill grinding efficiency, reduced the mill temperatures and resulted in feeder pluggages.

[162] NSPI also noted that the quality of the local Prince coal deteriorated in the relevant time period, further exacerbating the situation. However, Liberty states this is the risk when using poorer quality coal in that it can be unpredictable.

[163] In its Reply Evidence, NSPI summarized its view of the causes of the derations:

> 1. Many factors - moisture, initial sizing, wear, inlet temperatures - affect the performance of coal mills. In December, 2010, the Lingan Generating Station experienced a 1-in-30 year rainfall event. When coal contains unusual moisture levels, it reduces the temperature inside the coal mill, so the coal does not dry properly. Grinding efficiency and combustion are compromised, lowering generation. Coal with increased moisture levels has a greater tendency to build up on surfaces until the coal feeders that regulate the amount of coal going into the mills begin to plug up. When a feeder plugs, the flow of fuel to the boiler slows and the units are derated.
>
> 2. In December, the ash, moisture, and sulphur content of Prince coal all increased. The increased moisture resulting from the rainfall event, together with the increased ash content, reduced the effectiveness of the precipitators and led to derations. NS Power could not reasonably be expected to mitigate the effects of a 1-in-30 year event, especially one that coincided with high ash content in the coal received from a low cost supplier. When the impact of the record rainfall event began to subside, the Lingan units returned to full load capability.
>
> [NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 27]

[164] While Liberty stated in the FAM Audit that its review of the documentation "disclosed no expression of concern about opacity issues at the Lingan station" leading to the December 2010 derates, NSPI replied that it had identified the moisture issue and the precipitator performance, and its action to address the issue, in its April 2011 presentation of November - December Plant Performance.

[165] NSPI engaged Dr. Stan Harding to assist in its response to Liberty's claim of imprudence respecting the Lingan derates. He is a consultant with experience in coal generation facilities.

[166] Dr. Harding's conclusions included:

...

- The unusually high precipitation in December 2010 combined with the high moisture levels in the coal, resulted in significant boiler derates and mill pluggages during this time period.
- The load reductions noted in December 2010/January 2011 were primarily due to coal quality and high moisture-related pulverizer pluggages rather than opacity.
- The high precipitation in December 2010 would have resulted in an increase in mill pluggages and boiler derates even if a design coal was being used. ...

[Harding Report, Exhibit N-77, p. 14]

[167] NSPI also called Emily Medine as a witness on this issue. She is a consultant who regularly assists NSPI in its solid fuel management issues. In her view, Liberty ignored the impact of a 1 in 30 year rainfall event in December 2010, which she stated was the primary reason for the derates. She added that Liberty ignored NSPI's strategies for addressing all potential derates due to provincial limits on SO_2 emissions. She also noted that NSPI immediately dealt with the derates after 2010.

11.3.2 Findings

[168] The Board considers NSPI's evidence on the Lingan derating issue to be tenuous and unreliable in several respects.

[169] First, the Board has several concerns about the evidence of Dr. Harding.

[170] In Information Requests IR-6(d) and 7, Dr. Harding was asked to provide a description of the design and operational features at Lingan, including the spare mill capacity on each unit, which was designed to avoid unit operational consequences due to mill plugs. He was also asked to provide the number of pulverizers assigned to each of the four Lingan units and to provide information about the derates specifically caused by pulverizer pluggages, including the generating unit involved. He responded by stating that he had not received this information from NSPI. He stated that the issue of

spare mill capacity was outside his scope of work, although he acknowledged it was relevant to the derate issue.

[171] Based on Liberty's investigation, it confirmed that "Lingan’s use of four mills per unit allows for each unit to remain at full load with one of its mills down" [Liberty FAM Reply Evidence, Exhibit N-170, PDF p. 115].

[172] Surprisingly, in questioning by Board Counsel, NSPI Fuel Panel member John Hawkins acknowledged that Dr. Harding had asked him for information about spare mill capacity, but NSPI did not provide him with that information.

[173] As a result, on an issue as important to derates as spare mill capacity, which Dr. Harding conceded was a relevant consideration, he was not provided with the information, even when he inquired about it.

[174] Another aspect of Dr. Harding's testimony which concerns the Board is that he did not test the data for seasonality. In response to questions from the Board, he testified:

> MR. DHILLON: Now, did you consider expanding the database to consider the seasonality factor in the -- in your issues that maybe because a different season of the year might affect your results?
> MR. HARDING: That's a good question.
>
> No, I did not. The reasoning was the -- when I was contacted and asked to evaluate the data, the event was in December and so I had just asked for information a few months prior to that.
>
> And when I got the rainfall information, which is shown in my report also for November/December for the previous -- I think -- five years, I didn't -- I didn't go back any farther, for example, in 2009 or '08, anything like that, no.
>
> MR. DHILLON: So I guess did you go back five years in December each year?
>
> MR. HARDING: Just with -- just with -- no. Just with the rainfall data to show that it was indeed, a different -- something out of the ordinary occurred in December 2010 in terms of rainfall.
>
> …

> MR. DHILLON: But if you had considered wider data and there was derating beyond July to February the following year, would that have given any indication that there are reasons in the past this issue may have arisen and that there's reason to have some kind of a study done or something?
>
> MR. HARDING: Okay. That's a good point. I think had I noticed -- or had there been some information in this July-August-September time period that showed me that they were -- again, the -- we were focusing on de-rates due to opacity. So had there been some significant opacity de-rates -- de-rates due to opacity -- excuse me -- I would have asked for additional data.
>
> But since -- again, as I mentioned, perhaps not the greatest consultant, I should have asked for another study, but I didn't. Once I asked for the information I had, I -- it became quite obvious to me that there was an event, something happened in December of 2010 that was different than the previous five months that I had looked at. …
>
> [Transcript B, November 1, 2012, pp. 1304-1306]

[175] Further, despite Dr. Harding's theory that the derates were attributable to the December 2010 rainfall, the NSPI data requested by Liberty confirmed that the moisture level of the coal in July/August 2010, or after January 2011 (when the plant was not derating), was equal to or higher than moisture levels during the December 2010 deratings:

> ...The response to IR-8 shows moisture data from July 2010 through June 2011. The response to this IR-8 (see attachment II-2) shows several periods in July and August 2010 and in June 2011 with moisture levels at or exceeding the December 2010 [values](when a 30-year rain was experienced)...
>
> Thus, Lingan operated both: (a) in July and August 2010, without derating, despite equal or higher moisture levels than under the coal blend being used through the December deratings, and (b) after January 2011, without derating, despite equal or higher moisture levels than under the revised coal blend.
>
> [Liberty FAM Reply Evidence, Exhibit N-170, PDF p. 113]

[176] Accordingly, in the Board's view, Dr. Harding's opinion that moisture and mill pluggages caused the derates is not supported by the evidence.

[177] In the end, Dr. Harding's engagement seemed to have been simply to correlate the rainfall to the derates. However, he did not conduct a root cause analysis; he did not fully investigate the pluggages (including spare mill capacity); he did not

consider seasonality; and did not evaluate ash. Despite his undoubted expertise in this field, NSPI did not provide him with the information or the necessary latitude in his scope of work to conduct an independent evaluation of the Lingan derates. As a result, the Board is not able to assign much weight to his evidence, if any.

[178] The Board also concludes that it cannot accept the evidence of Ms. Medine in this proceeding. Counsel for Avon described the concerns with Ms. Medine's testimony:

> 40. The Avon Group respectfully submits that the objectivity of Ms. Medine's opinion that NSPI's actions were prudent during this time period is undermined by the fact that she was actively advising NSPI on the very issues (coal procurement and the Lingan derates) that are central to the disallowance recommendation. ...Ms. Medine's lack of objectivity was further apparent when she consistently referred to the actions of NSPI using the pronoun "we". She is now showing a laudable degree of loyalty to the utility, consistent with her long-term engagement by NSPI, but it appears to have coloured her perspective, to the extent that she would not even acknowledge that she characterized NSPI's actions in the 2002 GRA as "imprudent" despite being presented with her sworn response to IR which described NSPI's "imprudent practices".
>
> [Avon Final Submissions, November 23, 2012, para. 40]

[179] The Board accepts Avon's submission on this point.

[180] The Board observed Ms. Medine to be combative and non-responsive in her testimony at the hearing, as demonstrated by her refusal to acknowledge her recommendation of imprudence in the 2002 GRA hearing (where she previously appeared as a witness for Avon before being engaged by NSPI).

[181] She acted at times as an advocate, rather than as an expert witness. While the Board has accepted Ms. Medine's evidence on numerous instances in past proceedings, it concludes that her relationship with NSPI in its solid fuel activities, including the events related to the derates at Lingan, coloured her objectivity in this proceeding. The Board assigns little weight to her evidence.

[182] At the hearing, NSPI urged the Board to consider the benefits to ratepayers of NSPI staff "pushing" the limits of its generation fleet. Mr. Bennett stated:

> MR. BENNETT: We're not asking for a free pass, we're just asking for a realization that this is not easy, it doesn't happen by itself, and when you're pushing the limits in order to keep costs low, an unpredictable event like extremely heavy rains causes you to have to be nimble. And we've been as nimble as you can reasonably be without pushing costs up.
>
> [Transcript, November 9, 2012, p. 1720]

[183] The Board is mindful that the task of "pushing" the Lingan units is a challenging one for NSPI's staff. The Utility and ratepayers benefit from the high output that can be achieved from the successful operation of these units.

[184] However, the Board also expects NSPI to act prudently in the operation of its generation fleet, including Lingan. It is not reasonable for the Utility to push its coal plants while disregarding the known risks of its choices of coal blends over a period of time.

[185] Mr. Spangenberg noted the importance of foresight and proper operational planning in striking the appropriate balance:

> MR. SPANGENBERG: …what we're saying is that in the middle of the year, when they started to get an indication that they were going to have some operational problems in terms of opacity, the bell should have gone off and they said, "Now, how -- what can we do at this Lingan station to make sure we don't have trouble when the real high load period comes in the winter, in December, January and February? Because if we can't run this unit, we're going to have to go out and buy very expensive power from some alternate source. And we don't know what that's going to be, but generally the power is either going to be another combustion turbine generating more expensive power or power that you buy."
>
> And so the issue to them should have been, "Let's balance the economics." You know, inventory that you're talking about is an issue. The existing blend of contracts coming in is an issue. Cost associated with derating the unit should be an issue and what alternate energy was going to cost you.
>
> And they have models to perform these calculations, and they should have been doing that. So that's -- that's really ---

> MR. MARSHALL: So are you saying the trigger for this look they should have taken that at this would have come in, what, July or so, in the summer? You say they were beginning to experience some ---
>
> MR. SPANGENBERG: Well, this particular coal was not a surprise coal. They had been burning this coal for 10 years.
> …
> MR. MARSHALL: Local domestic coal.
>
> MR. SPANGENBERG: And that's the one that should have caused them to perk up their ears and say, "Hey, we'd better worry about what's going to happen in December to make sure that we've got this economical Lingan unit available to run and that we don't have to derate it because of opacity violations."
>
> [Transcript, October 29, 2012, pp. 100-102]

[186] The Board accepts Mr. Spangenberg's description of the appropriate balance that should be reasonably expected of NSPI in the operation of this type of coal fired plant.

[187] Based on its review of the evidence, the Board finds, on the balance of probabilities, that NSPI was aware in July/August 2010 that there were quality issues related to the Prince coal. NSPI also acknowledged "pushing" the Lingan plant in order to achieve maximum output. Notwithstanding this factual background, NSPI did not investigate and test other coal blends to mitigate the risks of the failure to meet opacity limits.

[188] In failing to mitigate the known risks of derates from using Prince coal, the Board finds that NSPI was imprudent. The Board also concludes that imprudence on the part of NSPI led to the derate of the Lingan facility.

[189] Accordingly, the Board orders a disallowance with respect to the derates.

[190] In the event of a finding of imprudence on the Lingan derate, Liberty and NSPI disagree on the calculation of the amount of the disallowance.

[191] The total $3.6 million amount of the disallowance proposed by Liberty is based on the sum of two $1.8 million amounts (the fact that the two amounts are identical is coincidental). The first $1.8 million relates to corrections made by Liberty to NSPI's assumptions in its calculation of replacement energy. The second $1.8 million disallowance was proposed by Liberty as a consequence of the fuel cost savings that NSPI could have realized if a prudent coal blend was used.

[192] In determining the disallowance, Liberty calculated a cost associated with replacement energy resulting from the 21% derating at Lingan. In its Reply Evidence, Liberty stated:

> The Audit Report calculated the cost consequences of Lingan December 2010 deratings using data for the whole month. We recognized that hourly data would provide a more accurate basis for calculation, but did not have that data at the time we provided the draft report to NS Power for comment. NS Power did not comment or provide hourly data then, but did so [later] in support of its determination that the number was $750,000.
>
> [Liberty FAM Reply Evidence, Exhibit N-170, pp. 20-21]

[193] In reviewing its calculation of the disallowance based on NSPI's methodology, Liberty made two adjustments. The first adjustment takes account of the reduced output from specific Lingan units in calculating the amount of replacement energy. Liberty modified this adjustment slightly to reflect that NSPI's model underestimated the amount of replacement energy resulting from reduced output at Lingan. The second adjustment made by Liberty to improve the accuracy of the calculation was related to the assignment and pricing of the replacement energy to the units that provided that power. NSPI had applied a figure which reflected an average for all units in the fleet. Liberty concluded that the "true cost of the Lingan derates should be calculated at the margin, not homogenized over the other units…". Accordingly, Liberty calculated the Lingan replacement costs "at the top of the dispatch

stack rather than the average" [Liberty FAM Audit Reply Evidence, Exhibit N-170, PDF pp. 108-109].

[194] The Board considers these two adjustments in the calculation to be reasonable.

[195] Liberty also stated:

> …Our basis for the proposed disallowance is NS Power's decision to undertake operating risks without evaluating those risks and taking mitigating measures as deemed appropriate. The optimum solution could have resulted in higher or lower fuel costs. Taking the coal blend eventually utilized by NS Power in early 2011, which did indeed solve the opacity issues, our calculations show that fuel costs would have actually declined, not increased. Consideration of changed fuel costs, which NS Power appears to consider the appropriate method, would have thus produced an additional $1.8 million of avoided costs. That approach would call for increasing the proposed disallowance by that amount.
>
> [Liberty FAM Reply Evidence, Exhibit N-170, PDF p. 99]

[196] The $1.8 million disallowance calculated by Liberty as replacement energy cost did not take account of replacement fuel costs. As noted by counsel for Avon, it was NSPI which suggested that Liberty should have considered how fuel costs would have changed if a fuel solution had been introduced earlier. This methodology results in an additional $1.8 million disallowance attributed to fuel cost savings that NSPI could have realized if a prudent coal blend was used.

[197] The Board finds that it is appropriate to calculate the disallowance by considering, as NSPI suggested, how fuel costs would have changed if a fuel solution had been introduced earlier.

[198] Accordingly, the Board disallows $3.6 million related to the Lingan derates.

11.4 Natural Gas Contracts

11.4.1 Evidence

[199] With NSPI's long term natural gas supply contract with Shell (the "Shell contract") coming to an end on October 31, 2010, NSPI issued a Request for Proposals ("RFP") in September 2008 and August 2009 to acquire replacement quantities of natural gas to supply its projected needs.

[200] Four counterparties submitted seven proposals in response to the September 2008 RFP. One of the two lowest offers ("Bid A") was withdrawn after NSPI felt it had already accepted the offer via a term sheet. The other lowest offer ("Bid B") was rejected by NSPI, largely due to NSPI's concern about associated transportation costs and potential risk of supply interruption. That particular bid included primary injection into the Maritime and Northeast Canadian Pipeline ("M&NP-CA") at Goldboro but did not include primary delivery rights to the Tufts Cove plant. However, it did include firm secondary delivery rights to points along the M&NP-CA pipeline. Its duration was for eleven years, from November 1, 2010 to October 31, 2021.

[201] In the FAM Audit, Liberty addressed NSPI's natural gas purchases and highlighted issues regarding the two low contract bids which were not taken by NSPI. In recommending a disallowance of $5,969,252 for costs deemed to have been avoidable, Liberty identified five principal components associated with that cost determination. Those components included two base load contracts ($3,436,000), monthly purchases ($1,512,250), seasonal purchases ($276,800), and daily and intra-day purchases ($744,202).

[202] During the hearing John Adger, of the Liberty Group, was asked to explain how the $3.4 million proposed disallowance regarding the two base load contracts was

determined. His response was a simple calculation consisting of the daily contracted supply amounts in MMBtu between November 2010 and December 2011, multiplied by the price differential between the contracts taken and the lowest offers not taken.

[203] Also during the hearing Liberty was asked to provide their calculations of Bid B with transportation attached, which illustrated how long it would take for the commodity cost savings under that bid (with the transport cost included) to offset any transportation costs that would remain if NSPI was faced with an inability to continue using that transportation component at some future time. Liberty provided that information in their Undertaking U-15 which showed that the crossover point would have occurred about five years into the contract period.

[204] Regarding Bid A, Liberty acknowledged that there was not an accepted offer that was repudiated by Bidder A. Liberty's concerns were two-fold.

[205] Firstly, in early 2009, a subsidiary of Emera, Emera Energy Inc., entered into an agreement to market the Bid A gas. This was seen by Liberty as part of a pattern where the interests of Emera affiliates were favoured over NSPI.

[206] Secondly, Liberty felt NSPI should have been more aggressive with the offeror in attempting to obtain a suitable resolution to the issue.

[207] In his Pre-filed Evidence, dated September 17, 2012, NSPI's expert witness, Leonard Crook, stated that Liberty's characterization of Bid A is incorrect in just about all particulars. With respect to the other rejected offer, Bid B which included the transportation component, Mr. Crook stated that Liberty mischaracterized the offer to make it something that it never was.

[208] Mr. Crook recommended that the Board reject Liberty's proposed disallowance of $1,512,000 related to the first base load contract, as well as the proposed disallowance of $1,924,000 related to the second base load contract. He also recommended rejection of the proposed disallowance of $1,512,250 for excess monthly purchase costs and the proposed net disallowance of $1,021,002 associated with seasonal, daily, and intra-day purchases.

[209] In his Opening Statement at the hearing, Mr. Crook stated that:

> Liberty has an erroneous theory that all gas sold in Nova Scotia should be at a full Dracut netback price and NSPI overpaid whenever it bought gas at a price higher than that, although yesterday, Liberty does seem to have modified its position somewhat.
>
> ...
>
> Liberty's recommendations for disallowances follow this logic. As others have pointed out, this theory is incorrect and Liberty's recommendations based on it should be rejected.
>
> My testimony also challenges Liberty's allegations in the particulars of two specific decisions on bids to supply NSPI. Contrary to Liberty's assertions, the first offer, once it was clarified, not repudiated, was not at the price that we originally thought it was, but would have been at a price higher than the offer of the bidder whose NSPI -- whose gas NSPI ultimately selected. NSPI properly declined, after negotiation, to take this gas at the higher price, and the offer was withdrawn.
>
> …
>
> Contrary to Liberty's assertions, my recommendation to reject the second offer, which was an apparent full netback price, was based on sound judgment about the reliability of the supply and the risks associated with pipeline capacity.
>
> …
>
> Liberty maintains that secondary delivery rights under the M&NP Canadian tariff would have provided sufficient assurance of deliverability, but the Maritimes tariff is clear; secondary delivery rights are subordinate to primary firm delivery rights.
>
> The issue with the contract is fairly straightforward -- is a fairly straightforward matter. I considered it an unacceptable risk to take ownership of a long-term firm gas transportation contract for the purpose of delivering gas to a point not along the pathway of that contract, simply to access what might be a favourable supply contract that itself might not be reliable.
>
> [Transcript B, October 31, 2012, pp. 848-851]

[210] Regarding Bid A, Mr. Crook was asked about his understanding of the price stated by the offeror and about actions that should have been taken by NSPI when the offer was withdrawn. Mr. Crook confirmed that he and the NSPI team all understood the price to be the same as the price that was understood by Liberty. He also noted that this same understanding was presented to NSPI's Fuel Strategy Table where approval was granted to proceed with the contract. At that point NSPI emailed a term sheet to the offeror and understood that it had accepted the offer. It was not until about six days after the term sheet was emailed that NSPI was informed its price interpretation was incorrect.

[211] Board Counsel asked NSPI's fuel witnesses how NSPI dealt with the situation in order to ensure that its acceptance of the offer could be preserved. Ms. Trenholm stated NSPI did not want to damage the relationship with the counterparty. She confirmed that NSPI did contact Bidder A and expressed as strongly as they could their disappointment but did not feel they could negotiate a better price:

> … to express as strongly as we could our disappointment, at the same time acknowledging that this is a very illiquid market.
>
> This is actually a new counterparty for us…
>
> …
>
> …It wasn't to the point where it was enforceable, and that was our view, it is -- it's too bad, and it is really -- I think it as a lot of hopeful thinking, maybe, on our part that blinded us a little bit, that we didn't push on that more, to hope that we had actually got [redacted] pricing…
>
> [Transcript, November 9, 2012, pp. 2060 - 2061]
>
> MS. TRENHOLM: --- we had gotten an approval to transact with them… It was a simple misunderstanding, a confusion on their part.
>
> MR. OUTHOUSE: Did you attempt to negotiate a better price? Did you attempt to use that occasion to strike a better price than you had from [redacted]?

> MS. TRENHOLM: …They weren't willing to move off of that price; that was their final price.
>
> [Transcript, November 9, 2012, pp. 2065-2066]

[212] NSPI's primary concern with respect to Bid B, the rejected offer, was the risk of transportation interruption if the main line became full or congested.

[213] While the gas under that contract was favourably priced, indeed comparable to the price NSPI had enjoyed under the Shell contract, this contract had a transportation obligation attached to it with a secondary delivery point at Halifax. The primary delivery point was upstream of Halifax.

[214] NSPI pointed out that, to the best of its knowledge, no other market player in the Maritimes' market took an assignment of the Bid B contract.

[215] As noted, Liberty stated that, based on its analysis, the Bid B offer was sufficiently favourable in that after five years NSPI would have suffered no loss. In other words, there would have been a net benefit even if the balance of the transportation rights had become valueless at that time.

[216] This was explored with Liberty during the hearing:

> THE CHAIR: It's a contract with transportation attached. And I guess my question is, is it your opinion that that contract would, after approximately five years, have proved so valuable that even if Nova Scotia Power could not get the gas to Halifax after five years, customers would have been better off with the acceptance; is that what that line is telling me?
>
> MR. ANTONUK: That was actually the crossover point. Up to that -- if the crossover came roughly five years into the contract, on a strict economic basis, the offer that they rejected was better than the offer they accepted.
>
> THE CHAIR: So they only needed to get the gas to where they wanted it to go for five years?
>
> MR. ANTONUK: It was --- yes.
>
> THE CHAIR: In your opinion?

MR. ANTONUK: Yes.

[Transcript, October 29, 2012, pp. 332-333]

[217] During cross-examination of NSPI's expert witness, Mr. Crook, counsel for the Avon Group explored the issues regarding primary and secondary delivery rights on the M&NP:

MS. STEWART:

…

I just have a few questions about the gas contract that involved transportation rights. Would you agree that curtailment of secondary firm delivery on a pipeline would only occur when the pipeline capacity was fully contracted under primary firm contracts?

MR. CROOK: Depending on the locations of the -- of the pathways. My concern about that contract was that it was firm but outside the pathway that needed to have secure deliverability to the Halifax Lateral.

…

So you were right, it has to be -- all of the shippers have to be shipping at their maximum daily quantity or our – and that maximum daily quantity then precludes delivery of secondary -- of gas under secondary delivery rights.

MS. STEWART: And are you aware of whether or not there is today capacity on the M&NP Canada Pipeline?

MR. CROOK: The M&NP Canada Pipeline is not fully subscribed at this point.

MS. STEWART: Was it fully subscribed in 2008?

MR. CROOK: It was approximately, maybe 500, 520,000 out of the 600,000, I believe, was -- subject to check, of the maximum quantity of the pipeline. So you had some spare in there.

MS. STEWART: Has there, in your experience, been curtailment on the M&NP Canada Pipeline?

MR. CROOK: I'm not aware of any particular incident.

…

MS. STEWART: Sure, maybe I'll rephrase it. So there's been concern that there's risk associated with this contract, and the risk is that there -- because there's only secondary delivery rights, that in the event of curtailment the transportation that has been paid for would not be -- could not be used because it would only -- because there would be curtailment.

MR. CROOK: Correct.

> …
>
> MS. STEWART: Unless there is curtailment, secondary firm delivery is adequate to delivering gas?
>
> MR. CROOK: I'm going to hedge the question -- hedge my answer a little bit on that. It should be adequate. I think, depending on the pathway, it may have some bearing on that.
>
> …
>
> So if you have a firm delivery pathway that goes from Goldboro all the way to Baileyville and there is some curtailment on the pipeline, then -- that is, that the pipeline is at maximum capacity, you would still be able to deliver gas to some secondary points along the way, provided there wasn't, you know, firm there already blocking you.
>
> …
>
> MS. STEWART: And I think your answer there, again, was with the hypothesis that there is curtailment, and I understand what you're explaining, but I'm not sure that it was responsive to the question.
>
> So the question that I was saying was that, in the absence of curtailment, and the experience has been, and your evidence is that you are not aware of any curtailment on the M&NP CA, that without curtailment, secondary firm delivery is adequate and even possibly equal to primary firm delivery?
>
> MR. CROOK: Yes.
>
> [Transcript B, October 31, 2012, pp. 902-909]

[218] Following up on this questioning about transportation rights, counsel for the Province sought further clarification from Mr. Crook and asked if it was possible to have firm delivery rights on a lateral without having associated rights on the main pipeline. He replied that in order to get the natural gas to the specific lateral being discussed, transport along the mainline would be necessary. Firm delivery rights on the upstream lateral also include associated rights on the main pipeline in this instance. Mr. Crook also confirmed that payment for service anywhere on the M&NP, with a primary delivery point on the lateral, is covered by a single postage-stamp toll.

[219] Board Counsel also sought further clarification on this issue.

> MR. CROOK: Well, as I say, it's a common practice in the industry that you can -- that you can deliver to secondary delivery points along your pathway as long as that secondary delivery point is available. Outside your pathway you can't.
>
> MR. OUTHOUSE: And so when I read the tariff which says a particular customer who has a primary delivery point on the pipeline and -- primary delivery point, and then says that he can deliver anywhere else on the pipeline at a secondary delivery point that doesn't apply, that doesn't apply to this particular customer?
>
> MR. CROOK: It applies as long as there's capacity available on the Mainline, but it doesn't -- the problem would occur is if sometime between now and 2021 some congestion would occur onto the Mainline…
>
> [Transcript B, October 31, 2012, p. 919]

[220] Mr. Crook provided a response to Undertaking U-16 regarding available capacity on the Canadian portion of the M&NP. Mr. Crook advised that the physical capacity of the M&NP is 600,000 MMBtu per day. During 2008, the contracted capacity was 511,792 MMBtu which represents about 85% of the physical capacity. He also stated that the average daily flow throughout 2008 was 482,091 MMBtu or 80% of capacity. In addition, the average daily flow during March 2008, the peak month, was 527,383 MMBtu or 88% and on the peak day, also during March 2008, the maximum flow was 560,098 MMBtu or 93%. These figures clearly indicate that throughout 2008, capacity was available on the main pipeline to accommodate secondary delivery rights.

[221] Mr. Crook also noted that the pipeline capacity on the US side of the border was higher than the Canadian side in order to accommodate additional flows from the LNG facility at Canaport.

[222] Board Counsel sought further clarification of transportation rights:

> MR. OUTHOUSE: Mr. Crook you remember yesterday when we were discussing this we were looking at 6.1?
>
> MR. CROOK: Correct.
>
> MR. OUTHOUSE: And it says:
>
> "That the quantity is nominated for transportation by customers shall be scheduled by Pipeline for receipt and delivery in the following order." (As read)

And the first tier in that order, the first tier of customers:
"Firm service utilizing primary points of receipt and primary points of delivery." (As read)

Right?

MR. CROOK: Yes.

MR. OUTHOUSE: And the second (b) is:

"Firm service utilizing second points of receipt and/or second points of delivery provided, however, that if a pipeline is restricting service at a particular receipt or delivery point, then a customer utilizing that point as a primary point, regardless of the status at the corresponding delivery or receipt point, shall have priority over a customer using that restrained point as a secondary point or receipt of delivery." (As read)

In other words, and my understanding of that and you can correct me if I'm wrong obviously, is that if I have -- if both of us have primary receipt points at Goldboro and I have a primary delivery point at Halifax and you have a primary delivery point in Saint John and there's a constriction at Saint John, then you have priority over me at Saint John; is that correct? If I want to use my secondary rights to deliver to Saint John and it's a primary point of delivery for you, you have priority over me in scheduling.

MR. CROOK: You mean, if I -- mine was at Halifax?

MR. OUTHOUSE: If -- no.

MR. CROOK: I'm sorry, I ---

MR. OUTHOUSE: If your primary point of receipt -- of delivery is Saint John, my primary point is Halifax.

MR. CROOK: Yes.

MR. OUTHOUSE: And there's a constraint at Saint John, but I'm trying to get in there using my secondary delivery rights, you have priority over me because it's your primary point of delivery?

MR. CROOK: Yes.

MR. OUTHOUSE: Correct?

MR. CROOK: I believe so.

MR. OUTHOUSE: All right. But if neither of us have primary points of delivery at Saint John, but we both want to exercise secondary rights to deliver there, we're on an equal footing; are we not?

MR. CROOK: Yes.

MR. OUTHOUSE: Okay. And when you look at 6-3, and this is the part that wasn't in the tariff that's in your document. Six three (6-3) says that:

"In the event a tie for capacity exists among category A, B, C, or D customers, quantities within that category will be scheduled pro rata on the basis of the customer's MDTQs." (As read)

Correct?

MR. CROOK: Yes.

[Transcript A, November 1, 2012, pp. 937-941]

[223] In an effort to obtain a better understanding of the pipeline constraint issue, the Board requested further clarification from Mr. Crook:

> THE CHAIR: So I guess once it enters the Mainline, I'm having difficulty understanding what the constraints are, then getting it to the Halifax Lateral given that there's no gas entering the Maritimes & Northeast Pipeline between Goldboro and New Glasgow, where the Halifax Lateral comes off. Could you help me with that?
>
> MR. CROOK: My understanding is that there is a decline in pressure over the length of the line and that you can take quantities off a short distance down the line and not affect -- and by terms of the tariff then, you have secondary rights to any downstream takeoff points from your -- from the [redacted]. I'm not a pipeline engineer so I don't know exactly ---
>
> THE CHAIR: So are you saying that ---
>
> MR. CROOK: --- the dynamics of the flows.
>
> THE CHAIR: So if you put 600,000 MMBtu's in at Goldboro, you're saying you can't get that to, say, New Glasgow?
>
> MR. CROOK: Point taken. Yeah, I'm not sure then.
>
> THE CHAIR: And you'd agree with me that no gas enters that line, or frankly, is likely to enter that line between Goldboro and New Glasgow?
>
> MR. CROOK: That's correct.
>
> [Transcript A, November 1, 2012, pp. 995-996]

[224] Mr. Crook was asked if he did any economic analysis of the price of gas under Bid B, compared to the contract that eventually was entered into by NSPI, to determine what the economic benefit would have been versus the risk on the pipeline. His response was that he did not do the sort of analysis that Liberty had done with respect to the benefit of the contract. Likewise, John Reed, another one of NSPI's expert witnesses, did no such economic analysis.

[225] As NSPI's generation pattern moved toward greater reliance on gas-fired units, a requirement for additional supplies of natural gas was identified. In addressing that need, NSPI entered into a number of short-term agreements resulting from bilateral negotiations, rather than through an RFP process. These purchases consisted of various forms of seasonal, monthly, daily, and intra-day agreements and involved a range of transaction pricing. In the FAM Audit Report, Liberty identified excess costs of $276,800 for seasonal purchases, $1,512,250 for monthly purchases, $767,706 for daily purchases, and an intra-day saving of ($23,504). Liberty's calculations are based on the difference between the price paid by NSPI and the price that Liberty determined NSPI could have achieved with more informed and aggressive negotiations and with access to LNG from Canaport.

[226] NSPI responded to those conclusions regarding excessive costs for natural gas by dismissing Liberty's assertions that lower prices could have been achieved. NSPI stated that it is committed to champion customer interests in the pricing of natural gas supplies and it takes the position that Liberty is confused about the operation of the natural gas market in the Maritimes.

[227] In his Pre-filed Evidence, NSPI's expert witness, Mr. Crook, addressed the excessive procurement costs identified by Liberty regarding seasonal, monthly, daily and intra-day purchases. Mr. Crook noted that the characteristics of gas contracting include various obligations such as delivery, duration, and different supply tranches which will result in gas prices that are higher than those attributed to basic gas commodity trading. He also stated that:

> …My observation here is that in the daily and intraday market, where supply is short, one can expect to pay higher prices than when supply is at surplus or for previously contracted supply. The argument that these volumes also should have been priced at

> [redacted] misunderstands the operations of the gas market. Liberty's recommendations for eliminating these expenditures from the FAM should be rejected by the Board.
>
> [Exhibit N-129, p.10]

[228] Mr. Reed also disagrees with Liberty's recommended disallowances for NSPI's seasonal, monthly, daily and intra-day purchases. In his direct evidence, Mr. Reed stated:

> Liberty believes that higher natural gas prices in the Maritimes that have been experienced since the expiration of NSPI's Original Shell Contract are inconsistent with the NEB's prior findings regarding exports of natural gas from Canada. Liberty states that "NSPI's expectations of [redacted] did not appear to be consistent with either the general regulatory regime for gas exports from Canada or the specifics of the authorities granted to Repsol." (Liberty Audit, p. III-5).
>
> [Exhibit N-134, p. 25]

> …it is my opinion that the changes in wholesale gas pricing in the Maritimes reflect exactly the way a functioning market would work as it moves from having a supply surplus to a supply deficit. The increasing natural gas prices in the Maritimes are not due to market flaws, but rather a shortage of indigenous supply.
>
> [Exhibit N-134, p. 31]

[229] He went on to say that in determining these disallowances, Liberty based its finding on its interpretation of prior NEB decisions regarding natural gas exports from the Maritimes. Mr. Reed stated that he agrees:

> …the NEB's policies are that the natural gas needs of Canadians are to be met on terms that are similar to those charged to export customers. However, I strongly disagree with Liberty's interpretation of these NEB rulings and how Liberty has applied its conclusions to NSPI's circumstances in this proceeding.
>
> …
>
> Contrary to Liberty's interpretation, the NEB has not previously concluded that purchasers of natural gas in the Maritimes are entitled to a Dracut netback price. In fact, the NEB specifically recognized in MH-2-2002 that producers/marketers selling in the Maritimes natural gas market are entitled to seek reimbursement for transportation costs to which they have committed.
>
> [Exhibit N-134, pp. 32 - 34]

[230] In its Closing Submission, with respect to Bid A, NSPI stated that Bid A suffered from vagueness in its terms such that NSPI and the bidder had two

understandings of the offer. NSPI argued that Liberty's position with respect to Bid A was not as much about the ability of NSPI to obtain competitively priced gas but related to Liberty's concern about affiliate transactions.

[231] With respect to these affiliate concerns, NSPI noted the evidence of its expert, Mr. Reed, who found no evidence that the affiliate or NSPI violated the Affiliate Code of Conduct or conspired in any way in connection with Bid A.

[232] In the final analysis NSPI stated that:

> NS Power could not have forced [Bidder A] to honour a proposal that [Bidder A] believed it had not made.
>
> [NSPI Closing Submission, November 23, 2012, p.66]

[233] NSPI goes on to state:

> Liberty initially claimed NS Power to have been imprudent in respect of the [Bidder A] offer because NS Power did not obtain the benefit of the pricing structure as that structure had initially been understood by NS Power. In contradiction to Liberty's position, the discussion could simply not get to a consideration of whether it was within the band of reasonable choices to have rejected the [Bidder A] proposal because there was no legally enforceable proposal on the table – a fact acknowledged by Liberty during its testimony. [Bidder A] withdrew its proposal and accordingly that alternative choice was simply not available. It cannot be unreasonable or imprudent not to accept an offer that no longer existed.
>
> [NSPI Closing Submission, November 23, 2012, p. 66]

[234] With respect to Bid B, NSPI argued as follows:

> NS Power had sought gas for terms of 1-5 years and up to 20,000 MMBtu/day. The [Bid B] offer had several components – one was a 4,000 MMBtu/day supply to which NS Power already had access, while the second was for a gas supply contract of 7,000 MMBtu/day of additional gas supply (non-firm for as many years as SOEP supply would support). The third and final component was 11,000 MMBtu/day of must-take pipeline capacity through a Firm Service Agreement whose term extended until 2021 – well beyond the term of the associated gas supply.
>
> It was NS Power's and ICFI's considered view that the value of the 7,000 MMBtu/day did not outweigh the risk of committing to paying transmission costs to 2021 on a portion of pipeline that has no (firm) primary delivery rights to the Halifax lateral. In fact, NS Power's financial analysis indicated that the contract would cost customers almost $20 million due to the capacity costs outweighing the cost of gas. Given what we now know about [Bid B], it is understandable that [Bid B] would have wanted to find a way out of its costly transportation contract.

> NS Power tried, and failed, to get firm transportation to Halifax. It is also worthy to note that [Bid B's] offer to sell gas under its proposed conditions was not accepted by any other buyer.
>
> [NSPI Closing Submission, November 23, 2012, p. 60]

[235] In its Closing Submission, Avon noted that NSPI's involvement in the regional natural gas market had been an issue of concern raised by Liberty in the 2010 FAM Audit and again in the 2012 FAM Audit. Avon also stated:

> The evidence that has emerged through this process demonstrates that while NSPI has a strong understanding of the complexities of the natural gas market, it tends to take a conservative approach to its role within the market and, in some key instances, failed to undertake rigorous analysis of its natural gas contracting and hedging options. As a result, stakeholders are left to question whether NSPI has truly made every reasonable effort to ensure that it is obtaining the lowest possible natural gas prices.
>
> [Avon Closing Submission, November 23, 2012, p. 8]

[236] Regarding NSPI's activity with natural gas contracts, Avon noted that NSPI and its expert witnesses have repeatedly stated that natural gas prices, as low as those contained in the two lowest bids from the 2008 RFP, have not been seen for several years. Therefore, prior to rejecting the bids:

> One would expect that this decision would come after a serious analysis of the financial and operational risks associated with the bids. However, it appears that this is not entirely the case.
>
> [Avon Closing Submission, November 23, 2012, p. 9]

[237] Regarding the lowest bid which had been withdrawn (Bid A), Avon stated this situation appeared to be:

> …a significant miscommunication between NSPI and the counterparty, at best, or interference from an NSPI affiliate, at worst.
>
> …In the NSPI evaluation of the RFP outcomes, this bid was ranked number one. Based on the wording of the bid and ongoing negotiations, it was widely believed by NSPI and its consultant, Mr. Crook, that the counterparty was offering gas with a deduction for both Canada and US pipeline transportation charges.

> The bid was selected by staff and was presented for approval to the Fuel Strategy Table; upon approval, a term sheet was provided to the counterparty. Only then did the bidder indicate that it had only intended to deduct a portion of the transportation costs. This significantly changed the economics of the bid and, ultimately, the offer was determined to be unfavourable. It is surprising that there would be such a significant miscommunication between NSPI and a potential counterparty.
>
> [Avon Closing Submission, November 23, 2012, p. 12]

[238] Although NSPI testified that it had discussed this situation with the counterparty and voiced its dissatisfaction with what appeared to be a change in the bid, Avon noted that:

> NSPI's full reaction to the clarification with respect to the bid did not become apparent until Ms. Trenholm was under cross-examination during the audit hearing. Only then, did it come to light that NSPI voiced significant discontent with respect to the sudden change in the counterparty's bid. Ms. Trenholm stated that although NSPI was "indignant", the Utility ultimately preferred to preserve the relationship with the counterparty and so decided not to press the matter further. It is noted that both NSPI and Liberty agree that the bidding process, though advanced, had not, yet, resulted in an enforceable contract.
>
> [Avon Closing Submission, November 23, 2012, p. 13]

[239] Regarding the rejected bid with the transportation component (Bid B), Avon noted that there was no dispute that NSPI would have accepted the bid if it did not have the specific transportation component attached to the offer. In this instance, Avon submitted that NSPI should have considered the actual capacity and forecasted capacity of the M&NP-CA pipeline as of 2008, prior to rejecting that bid.

> The transportation contract had firm entry rights at Goldboro and so would be unaffected by increased use of the pipeline by Deep Panuke gas, insofar as entry rights are concerned. The issue, then, is whether potential increased gas supply to be shipped on the M&NP-CA would impact delivery, on a secondary basis, to Tufts Cove.
>
> …We understand that Mr. Crook was suggesting that secondary delivery along the pathway between the primary injection site and the primary delivery site would have priority over secondary delivery along another "pathway" on the pipeline. This position does not appear to be supported by the tariff provisions or the logic of a postage stamp pipeline system, such as the M&NP-CA Pipeline.
>
> Despite taking this position, Mr. Crook was not able to provide an example of priority being affected by pathways on a postage stamp pipeline in Canada…

> …Little or no evidence was given with respect to sources of curtailment, either additional injections of gas between Goldboro and the Halifax Lateral or other major primary delivery rights' holders to the Halifax Lateral. Therefore, it seems that there was no particular risk of curtailment with respect to the intended secondary delivery point at Tufts Cove.
>
> …
>
> It is submitted that the risks associated with secondary delivery to Tufts Cove were not exceptional and that, in light of the preferential pricing of the natural gas that was being offered in the bid, one might expect that NSPI would undertake a rigorous financial analysis to determine whether the economic benefits outweigh the risks associated with the transportation portion of the contract. However, it does not appear that such an analysis was undertaken prior to rejecting the bid.
>
> Although NSPI produced a table comparing the benefits (gas) and liabilities (transportation) associated with this bid, the Utility confirmed that this assessment was undertaken after-the-fact as part of NSPI's response to the 2012 Audit and that no economic analysis had been performed in 2008, because the "*exposure was easily understood at that time*."
>
> Ms. Trenholm confirmed, on behalf of NSPI, that although Mr. Crook undertook an informal risk analysis of the contract, he did not produce an in depth economic analysis, either. Further, Mr. Reed gave evidence that he did not undertake any type of analysis in relation to preparing his evidence…
>
> [Avon Closing Submission, November 23, 2012, pp. 10-11]

[240] Avon went on to point out that Liberty's analysis determined that the risks associated with the transportation component of Bid B would be outweighed by the benefits of the natural gas contract after about five years. Avon concluded that:

> … the risks associated with the transportation contract were not properly analyzed, either by NSPI or its consultants, and a contract that could have provided gas at a price that NSPI acknowledges it has not been seen in many years was rejected without the type of rigorous analysis one might expect in this situation. In these circumstances, the Avon Group supports a finding of imprudence with respect to NSPI's rejection of this contract.
>
> [Avon Closing Submission, November 23, 2012, p. 12]

[241] The Small Business Advocate, in its Reply Closing Argument, stated:

> The FAM Audit Report provided recommended finding V-1, that added fuel costs were incurred due to NSPI's inaction addressing gas market conditions, which the Board's consultant recommends should be a disallowance of $6 million. The SBA supports this finding because NSPI has not provided sufficient evidence in this proceeding or in its closing submission that this incremental cost could not have been avoided had NSPI

> pursued earlier efforts to replace expiring contracts as well as more negotiated more aggressively for more favorable pricing terms in replacement contracts.
>
> [SBA Reply Closing Argument, November 30, 2012, p. 3]

11.4.2 Findings

a) Bid A

[242] The Board does not believe that NSPI's actions with respect to Bid A were imprudent. Based on the evidence, it appears to the Board there was never a meeting of the minds between NSPI and Bidder A on the terms of the offer. Initially NSPI, and their advisor Mr. Crook, thought NSPI had a very favourable offer and recommended it to NSPI's Fuel Strategy Table. They agreed to accept it. However, when the term sheet confirming acceptance was presented to Bidder A, it then became clear that there was not agreement on the proposal. Liberty acknowledged that there was not an enforceable contract.

[243] While it may be argued that NSPI should have more aggressively pursued Bidder A to obtain a favourable compromise price, the Board does not believe NSPI's failure to do so was sufficient to meet the test of imprudence. Concern about the future business relationship with Bidder A is a relevant concern for NSPI to have taken into account.

[244] Finally, while Liberty was right to be concerned that Bidder A entered into a subsequent contract for the same gas with Emera Energy Inc., there is no basis, in the Board's view, to find that activity frustrated the contract or that NSPI played any role in the contact between Emera Energy Inc. and Bidder A.

b) Bid B

[245] The Board is very concerned about NSPI's failure to properly analyze the costs and benefits of taking an assignment of this very favourably priced contract.

[246] For ten years under the Shell contract, which expired in 2010, NSPI enjoyed a gas price that was favourable vis-à-vis the Dracut hub. The Bid B contract would have permitted that favourable pricing to continue, albeit for a much smaller volume of gas, possibly for an additional eleven years.

[247] NSPI stated that the gas supply contract was available "for as many years as SOEP supply would support". Mr. Crook noted that the gas supply contract had renewable provisions that made it potentially attractive.

[248] NSPI spent a great deal of time explaining during the hearing, principally based on the evidence of Mr. Reed and Mr. Henning, that the evolution of the gas market in the Maritimes had taken place in such a way that gas is now being less favourably priced in the Maritimes, vis-à-vis the Dracut hub, to the point where it is virtually impossible to obtain Dracut minus bids.

[249] Based on this evidence, by foregoing the Bid B contract, NSPI has passed up an opportunity that may never present itself again, at least in the foreseeable future.

[250] What appeared to concern NSPI was the associated transportation capacity. Halifax would have been a secondary delivery point on the M&NP pipeline.

[251] The evidence, however, is that virtually all of the gas being delivered to Tufts Cove is being delivered pursuant to transportation contracts where Halifax is a secondary delivery point. While a shipper with Halifax as a primary delivery point would have priority over other shippers with only secondary delivery rights to come to Halifax, there were no such shippers. If there were to be any constraints on the M&NP pipeline,

those with secondary delivery rights would share the capacity pro rata. However, in 2008 the M&NP pipeline was not being used to its full capacity. There was never a day, based on the evidence of Mr. Crook, where the pipeline capacity was met or exceeded.

[252] Mr. Crook's principal concern seemed to be that somehow the gas would not get to Halifax. That is not logical to the Board. The gas destined for the Bid B primary location must enter the M&NP mainline. It then proceeds along the M&NP pipeline until it reaches the upstream lateral leading to the primary delivery point. The Halifax lateral meets the M&NP pipeline near New Glasgow. There is no gas being injected into the M&NP pipeline between the take off point for the upstream lateral and the Halifax lateral. In the circumstances, therefore, it is not at all clear to the Board what the risk was that NSPI thought it was avoiding. Mr. Crook as much as conceded that under questioning from the Board.

[253] Liberty prepared an analysis that showed that NSPI was better off after five years, based on this favourable pricing, as compared to other pricing it was able to obtain even if the transportation contract was useless from that point forward.

[254] It is apparent to the Board that NSPI, at the time, did no such analysis.

[255] NSPI, in its Reply Brief, included a section which attempted to criticize and undercut Liberty's analysis. The Board is very concerned that this analysis was not made available in NSPI's principal argument and, by saving it for the Reply Brief, no party had a chance to respond or comment on it. In the circumstances, while the Board has reviewed this submission, the Board gives little weight to that analysis.

[256] In the Board's view, NSPI was imprudent in failing to properly analyze the risks and benefits associated with the Bid B contract which the Board believes could have been very beneficial for ratepayers.

[257] In the circumstances the Board disallows $903,000 related to the failure to take an assignment of the Bid B contract for the period from November 1, 2010 to December 31, 2011 (i.e., 426 days). The details of the calculation are based on confidential information. As this was a longer term contract the impact of this finding on any future test years will be the subject of consideration in future audits.

c) Seasonal, Monthly and Daily Pricing

[258] Liberty's theory in recommending a disallowance with respect to monthly, seasonal and daily purchases has as its foundation its belief that inaction by NSPI contributed to the market conditions that existed.

[259] In terms of making its recommendation with respect to disallowance, it made certain assumptions as to how the market would have worked if buyers on the Canadian portion of the M&NP had access to LNG. On a seasonal basis Liberty felt there would be opportunities for NSPI to obtain favourably priced gas recognizing the volumes of LNG flowing into the U.S.

[260] All of this evidence was filed in confidence so it is difficult to be more precise about this calculation. Essentially what Liberty did was compare the market as it was compared to the market as it could have been.

[261] In respect to the Bid A and Bid B contracts, the circumstances are fairly clear and the Board is able to make a judgment as to whether or not NSPI acted prudently. With respect to seasonal, monthly and daily purchases the evidence is much

less clear. Based on the market conditions as the Board now understands them, and as more particularly described in the natural gas market section, the Board does not believe there is a sufficient basis for it to make any disallowance based on NSPI's monthly, seasonal or daily purchases. It is not at all clear to the Board that NSPI could have achieved what the FAM Audit suggests in terms of price in seasonal, monthly or daily contracts.

11.5 Natural Gas Markets

11.5.1 Evidence

[262] As noted elsewhere in this Decision, for ten years ending in late 2010, NSPI enjoyed the benefit of what is now considered to be a favourably priced natural gas contract with Shell Canada for Sable offshore gas.

[263] Indeed, during much of the life of that contract, NSPI was in a position of selling natural gas, not just purchasing it. The Shell contract provided much more gas than NSPI, in those years, could economically use to generate electricity. Among other things the Shell contract recognized, in terms of price, that Halifax was closer to the source of supply than the trading hub of Dracut, Massachusetts. By 2008, when NSPI started the process to find replacement gas, it appeared that market conditions had deteriorated with respect to the price for gas purchases in the Maritimes. It appeared that instead of paying a price that excluded transportation on the U.S. portion of the pipeline, NSPI would be faced with prices tending to a level reflecting increasing amounts of transportation from the Canadian border to Dracut because shippers had contracted for that capacity and, with dwindling gas supplies, needed to be reimbursed for that transportation commitment.

[264] In the 2010 Audit, Liberty made a number of recommendations to NSPI, including:

1. Become more proactive in obtaining competitive market prices for NSPI gas supplies;

2. Maintain contacts with existing sources of gas supply components and work aggressively to develop new ones.

[265] In both this audit and the previous audit Liberty expressed concerns that NSPI was being too passive with respect to obtaining competitively priced gas supplies by failing to be more aggressive with gas suppliers; by failing to take sufficient steps to enforce regulatory protections to Canadians, including the National Energy Board's ("NEB") Market Based Procedure; and, in Liberty's view, deferring to Emera affiliates with respect to the operation of the gas market.

[266] Liberty described the NEB's Market Based Procedure:

> The Board adopted in 1987 a new "Market-Based Procedure" (MBP) for reviewing export applications. This decision observes that:
>
> > *The fundamental premise of the MBP is that the marketplace will generally operate in such a way that Canadian requirements for natural gas will be met at **fair market prices**. However, the MBP was designed to provide for intervention if there was evidence that the market was not working to **adequately and fairly serve** Canadian needs.*
>
> This language does not define any of the emphasized terms. It does, however, appear to add a test beyond pricing at market, observing that whatever prices the market produces must be adequate to serve and fair in treating Canadian buyers.
>
> This decision describes the Complaints procedure in connection with export licenses as follows:

> *Under the Complaints Procedure, Canadian natural gas buyers have an opportunity to intervene with respect to an application for a natural gas export license if they believe they have not been able to purchase natural gas on terms and conditions that were **similar** to those of the proposed export. [Emphasis in original]*

[Exhibit N-171, pp. III-5 to III-6]

[267] Liberty relied significantly on a 2002 decision of the NEB where the Province of New Brunswick initiated an application requesting the NEB establish rules to apply when considering applications for short term exports for incremental supplies of Nova Scotia offshore gas. Gas exported under short term exports is subject to less regulatory oversight than long term licenses. While the NEB did not intervene directly in the exports of gas, it did signal that it would take on a heightened monitoring role.

> In summary, the Board is of the view that the developing Maritimes gas market faces many challenges that are not faced by buyers in the mature export market.
>
> Given these market realities, the Board shares the concerns of New Brunswick and PEI about access to incremental gas supplies on fair market terms. Although the Board does not believe that the record in this hearing warrants direct regulatory intervention, it did raise sufficient concern that the Board believes it must enhance its monitoring efforts in Maritime Canada

[NEB Decision MH-2-2002, Exhibit N-191, p. 42]

[268] Liberty also noted the NEB's findings in the Brunswick Pipeline decision related to LNG delivered to Canaport:

> The NEB stated as follows:
>
> > *… the Board is of the view that one aspect for the justification of this Project is its ability to provide an opportunity for access to a new source of natural gas supply to the Maritimes. While some parties expressed concerns regarding the ability of Maritime Canada markets to access the incremental gas supply provided by the Project, the evidence before the Board indicates that Irving Oil is the largest user of natural gas in Maritime Canada. Therefore, Irving Oil's access to the gas supply supports the Board's finding that there will be Canadian access to the Project's gas supply. Furthermore, Maritime Canada could also access this new natural gas supply source, to fulfill current and anticipated future natural gas needs, through the use of backhauls, swaps and direct connection to the Brunswick Pipeline.*

[Exhibit N-171, p. III-13]

[269] Among Liberty's conclusions with respect to NSPI's conduct in the natural gas market are the following:

1. NSPI has demonstrated that customers cannot rely upon it to champion their interests with respect to prices for natural gas in the Maritimes market;

2. NSPI should have been contesting and should continue to contest gas market circumstances; however there is no basis for confidence that it can be relied upon to do so even if it did undertake the effort.

[270] Liberty's view is that NSPI should have more aggressively pursued discussions with the NEB, including a possible application to the NEB, and been more active with respect to negotiations in the gas market reminding suppliers, among other things, of the Market Based Procedure.

[271] In NSPI's view, Liberty had a flawed understanding of how the U.S. Northeast and Maritimes gas market operates. NSPI submitted:

> The overwhelming weight of evidence is that NS Power's gas acquisition prices were sound and the contracts it achieved during the audit period delivered excellent value to customers.
>
> [NSPI Closing Submission, November 23, 2012, p. 51]

[272] NSPI, in its Reply Evidence, stated:

> Over the past five years, the balance of supply and demand in the Maritimes has shifted. Local supplies have dwindled, and local demand has increased. … Since January 2010, the usage of natural gas on the M&NP system (both M&NP Canada and MN&P US) has ranged from approximately 200,000 MMBtu/day to 500,000 MMBtu/day. On the other hand, estimated production of natural gas in Atlantic Canada has ranged from approximately 280,000 MMBtu/day to 340,000 MMBtu/day (excluding supply disruptions).
>
> …
>
> The current supply/demand imbalance, and the cost of the next available supply source, has caused the spread NS Power pays for natural gas supply … The price for natural gas supply in the Maritimes market will remain higher than it had been previously … until such time that supply and demand return to a more balanced state.
>
> [Exhibit N-98, pp. 34 & 36]

[273] With respect to its activity in the gas market, vis-à-vis customers and the NEB, NSPI points to a very favourable contract it entered into with a supplier for offshore natural gas. Unfortunately, supply conditions have not enabled NSPI to take full advantage of that contract through no fault of NSPI.

[274] With respect to the interaction with the NEB, NSPI stated as follows:

> NS Power has not filed a complaint with the NEB over the gas supply/pricing structure. Nor has any other natural gas customer in this market. NS Power continues to believe there are no grounds for such a complaint. Apparently all market participants and stakeholders in the Maritimes market except Liberty agree. If circumstances change in the future such that filing a complaint with the NEB may have merit, NS Power will re-evaluate accordingly.
>
> [Exhibit N-98, p. 39]

[275] With respect to LNG gas, NSPI pointed out that it is not economic to purchase gas at international LNG prices and bring the gas to Nova Scotia.

[276] In the view of NSPI's expert witness, John Reed, the change in market pricing in the Maritimes is not due to market flaws as he says Liberty alleges, but reflect a change in the market circumstances because of the region's shortage of supply. With respect to market conditions in the Maritimes and the role of the NEB, Mr. Reed stated as follows:

> …it is telling that no other market participant in the Maritimes filed a complaint with the NEB to correct what Liberty concludes are market failures. In other words, of the many sophisticated market participants that were also affected by the market conditions for which Liberty has expressed concern in the audit, not one deemed that filing a complaint had merit. …
>
> Therefore, since NSPI's conduct in the market was consistent with all of the other sophisticated market participants that were also affected by changing market dynamics and prices, NSPI's conduct cannot be deemed to be outside the range of reasonable behavior during this same time period. …
>
> Furthermore, even if NSPI had asked the NEB to intervene in 2010 and the NEB had complied, it is not at all likely that the NEB's review would have led to lower gas prices for NSPI, and, presumably, if it did, that outcome would have been some years into the future, not for 2010/2011.
>
> [Exhibit N-85, p. 27]

[277] On November 9, 2012, the last day of hearing and in a confidential session, NSPI disclosed new and important evidence concerning its activities in the market. Unfortunately, because of its confidential nature, the Board can disclose little, if any, of this evidence in this public Decision.

[278] It turns out that NSPI had indeed consulted a leading Calgary law firm concerning a possible complaint to the NEB and received advice. In part, based on that advice, NSPI had engaged in much more aggressive behavior with possible gas suppliers concerning price leading, in its view, to favourable pricing. NSPI also explained its strategic view with respect to LNG supply and its importance for supplying additional gas to a gas constrained market and the favourable effect that may have on the Maritimes market.

[279] Liberty had been advised in March of 2012 that NSPI had contacted outside counsel in 2010 but no reference to the fact they had contacted counsel prior to negotiations with the gas supplier where the favourable price was obtained. When asked about counsel's advice Liberty was advised by NSPI it was privileged.

[280] The Board was concerned as to the extent of Liberty's knowledge of this information, which came out on the last day of the hearing and asked for an Undertaking from Liberty, who responded in part as follows:

> This undertaking addresses Liberty's knowledge of contacts that Mr. Janega testified he had with outside counsel and with [redacted] about NEB authority to address market concerns. To summarize, we were not aware until reading the transcript of Mr. Janega's reported contacts with outside counsel. We were aware that NS Power did communicate with [redacted] about supply, but not as Mr. Janega described those contacts.
>
> Regarding consultation with outside counsel, we have no recollection of Mr. Janega's having discussed with Liberty any consultations regarding authority of the NEB to address gas market issues of concern to NS Power. A search of our notes since 2008 for reference to any such discussion found none. The issue of response to market concerns has been of interest to us since late 2008, at least. See for example, the April 2009 ICF International, *Report on Planning for Future Natural Gas Supply: A Review of the Activities of Nova Scotia Power, Inc.*, submitted by NS Power to the UARB, and

> discussed during this proceeding. That report came at the UARB's request, following our expressions of concern in the 2009 NS Power GRA. Thus, it is extremely unlikely that statements by Mr. Janega or anyone of this nature would have escaped attention.
>
> We addressed market-facing actions with Mr. Sidebottom in a March 31, 2010 interview during the prior FAM audit. He cited no communications with attorneys. He did say that he viewed [redacted] favorably, and cited no problems or concerns. He stated that he and Mr. Janega sought a meeting with [redacted] following its failure to bid in the Fall 2009 gas supply solicitation.
>
> [Undertaking U-27, November 19, 2012, p.1]

11.5.2 Findings

[281] NSPI, in their Closing Submission, stated as follows:

> **After years of debate about the merits, or lack thereof, of filing a complaint with the NEB, it is now clear that NS Power has, in fact, done exactly what Liberty has wanted the company to do.** [Emphasis added]
>
> [NSPI Closing Submission, November 23, 2012, p. 59]

[282] The problem is that the extent and importance of this activity was not disclosed to Liberty, the Board, or the parties until the last afternoon of the hearing. NSPI says in its submission that this should have been clear from a reading of Responses to Information Requests during the 2010 FAM proceeding. The Board has re-read those responses and, while they do disclose details of contractual negotiations with the counterparty, they do not disclose in any way the evidence that was provided by Mr. Janega on the last afternoon of the hearing and its importance and effect. Even if the 2010 FAM Information Responses did disclose this information it seems odd NSPI would suggest the Board must plumb the depths of the evidence in a prior proceeding to find it.

[283] The Board's dismay and concern about this cannot be overstated.

[284] A fundamental underpinning of Liberty's criticism of NSPI over the years was NSPI's failure, in the view of Liberty, to pursue regulatory avenues open to it and,

as a companion to that, to more aggressively pursue marketers of gas, recognizing the existence of the Market Based Procedure.

[285] In 86 pages of FAM Audit Reply Evidence, the evidence provided by Mr. Janega was not disclosed. The Board can only assume that if NSPI had been forthcoming on the consultations with a leading Calgary law firm and conversations NSPI had with the counterparty following those consultations, in the thousands of pages of evidence and IRs and in the hearing, the nature of the Audit and most certainly the nature of the hearing, one of the most rancorous the Board has ever seen, would have been very different.

[286] NSPI's actions in withholding this information are both inexplicable and inexcusable.

[287] NSPI has criticized Liberty to the point of ridicule for this recommendation in the present Audit and, previously, that NSPI should more aggressively pursue discussions with the NEB and be more active with respect to negotiations with gas marketers given the existence of the Market Based Procedure.

[288] Remarkably, NSPI now says it was, in fact, following Liberty's advice which has been given over a period of four years. The Board cannot understand what NSPI thought it was doing by withholding that information and continuing to ridicule Liberty for making the recommendation.

[289] While it may have been slow to act, it now appears NSPI was acting appropriately with respect to their consultation with the Calgary lawyers and in certain of their recent dealings with suppliers, as a consequence. However, the failure to disclose that has added significant time, cost and rancor, unnecessarily, to this hearing.

[290] In the Board's view, that conduct cannot go unsanctioned. The Board will impose a financial disallowance as more particularly described in Section 11.10 of this Decision.

[291] In its Final Submission, Avon stated as follows:

> 158. It is understood that there is a long-standing disagreement between NSPI and Liberty with respect to the level of engagement or aggressiveness that NSPI ought to be demonstrating in respect of the development of the natural gas market in the Maritimes. The Avon Group agrees with Liberty that NSPI has demonstrated an unreasonably passive approach to the natural gas market and that it is likely that a more aggressive approach, one that is commensurate with NSPI's purchasing power in the market, may have produced more economically priced gas contracts for NSPI customers.
>
> 159. It would be acceptable if NSPI had tried and failed but it is problematic, from the perspective of the Avon Group, that NSPI continues to insist that the market is behaving well and that there are no problems that require the Utility's intervention. NSPI's approach to natural gas market, in the Avon Group's opinion, has had detrimental effects and leads us to question whether NSPI has made every reasonable effort to obtain economically priced natural gas.
>
> [Avon Final Submission, November 23, 2012, p. 29]

[292] That submission was made even with the knowledge provided by NSPI in the last day of the hearing.

[293] The Board accepts that the gas market in the Maritimes has in recent years posed significant challenges to NSPI and other gas users. Mr. Reed described those challenges in response to a question from Board Counsel:

> In fact, the prevailing market of course represents the confluence of all of those sources of supply and what you see in the Maritimes market is that the marginal source of supply sets the prevailing price and that marginal source of supply has shifted from being indigenous production to production that's outside the region. And in fact, as you start to bid gas away from either the Portland system or Dracut, you end up having to pay a higher price. In fact you -- again that marginal resource is setting the prevailing price in the region and that marginal resource is now coming from someplace else.

> I expect that actually long term certainly will be the case. We may have an interim period in which the new gas causes us to go back to a Dracut netback market for a period of time; that would be great if it did. But long term, most people expect that in fact, gas will flow from south to north, into the Maritimes and that will be a Dracut-plus pricing regime. Even though there may be production in the Maritimes, the marginal source of supply will be from elsewhere.
>
> [NSPI Closing Submission, November 23, 2012, p. 52]

[294] The Board accepts that the pricing dynamics of the Maritimes gas market have changed over the last few years as explained by Mr. Reed.

[295] Indeed, the evidence provided by Mr. Reed has given the Board an enhanced appreciation of how the gas market is unfolding in the Maritimes.

[296] Circumstances have given NSPI limited room to maneuver with respect to gas pricing given the shortage of supply.

[297] Finally, Liberty expressed its continued concern about affiliate relationships and, in particular, Emera's relationship as owner of the Brunswick Pipeline, with the principal shipper Repsol, a company who was also a dominant player in the Maritimes gas market. These concerns are reinforced by the fact that the Maritimes market is currently not transparent and is not liquid. The market has few buyers and sellers and a dwindling supply.

[298] While the Board is, and has been, concerned about affiliate relationships and as a consequence has imposed a rigorous code of conduct on NSPI, the Board does not see evidence in this proceeding which would, applying the test of a balance of probabilities, cause it to make any disallowance because of affiliate activity.

[299] In the circumstances, the Board makes no other disallowance with respect to NSPI's gas market activity. The Board, in future, expects NSPI to do "exactly what

Liberty has wanted the Company to do" with respect to aggressively pursuing any reasonable opportunities to purchase gas at as competitive as possible prices.

[300] Again, much of the evidence on this topic was filed in confidence and, accordingly, the Board is only in a position to give an overview of both the evidence and a summary of its findings.

11.6 Natural Gas Hedging

11.6.1 Evidence

[301] A common reference point for the pricing of natural gas in the Northeast is at Dracut, Massachusetts. The Henry Hub, a distribution hub at Erath, Louisiana, is used as the pricing point for natural gas futures contracts traded on the New York Mercantile Exchange (NYMEX). The price difference between the Henry Hub and another trading hub, including Dracut, is called the "basis differential", or simply, the "basis".

[302] In the winter of 2010-11, there was a marked increase in the "basis differential" with Dracut as a result of a series of events (referred to as a "basis blowout"), causing NSPI's natural gas costs to rise.

[303] Liberty found NSPI's natural gas costs for November and December 2010, and at least January 2011, were unreasonably high due to the Company's failure to hedge Northeast Market "basis". As a result of this finding, Liberty recommended the Board defer NSPI's recovery of $12.8 million pending a study of what hedges would have resulted under a properly designed hedging program for the winter of 2010-2011 and determine based on that program whether there would have been a cost associated with what Liberty identified as imprudent.

[304] The Northeast Market "basis blowout" was described by NSPI as follows:

> A series of events starting in December 2010 caused the Dracut basis differential to rise throughout the winter of 2010-2011. First, the Henry Hub did not experience its usual winter price increase, so the baseline for the basis differential was lower than normal. Second, unusually cold weather in the northeast caused supplies in the area served by the Dracut hub to tighten. Third, severe weather prevented LNG tankers from docking at the Canaport terminal in Saint John, further exacerbating the supply shortage. Finally, in February, the Trans-Canada Pipeline ruptured and exploded at Beardmore, Ontario, 190 kilometres northeast of Thunder Bay, Ontario. This temporarily cut off supplies of Western Canadian gas to the Trans-Quebec and Maritimes pipeline and the Portland Natural Gas Transmission System, which serve the northeastern US. All these factors conspired to drive up the Dracut basis in an untypical and unforeseeable manner.
>
> [NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 54]

[305] Liberty indicates this $12.8 million is a place-holder based on results NSPI provided as the potential savings for the two months, November and December 2010, extrapolated over the five winter months. A study was undertaken by NSPI after the “basis blowout” event in December 2010, related to the need to hedge the “basis”. However, Liberty indicates this study did not provide the proper hedging program to accomplish the objective of reducing basis volatility at least cost, nor did it identify the appropriate financial instrument that would accomplish this.

[306] NSPI indicated they appropriately considered these risks and addressed the risks associated with the change from the long-term Shell contract that expired October 31, 2010, stating the only significant change in risk was moving from monthly to daily pricing and that there was no material impact to basis exposure.

[307] NSPI took the position that its hedging during this period aligned with the objectives and requirements of the Fuel Manual, and that the direction within the Fuel Manual does not allow them to hedge the “basis”. It claims an appropriate study was completed in anticipation of the changes related to the long-term Shell contract, indicating it retained Black & Veatch to undertake a comprehensive study of natural gas pricing risks. Black & Veatch did not identify any need to change NSPI’s approach to

basis risk or hedging. This report dated November 23, 2010 was entered into evidence during the hearing. The Board agrees the Utility's consultant on hedging objectives and risks did not identify the "basis" risks. However, the Board notes that the scope of the study does not expressly include the assessment or identification of basis risks and the study makes no mention of them.

[308] NSPI also indicated their assessment of the risks associated with the expiration of the long term contract resulted in the implementation of swing/swaps at Henry Hub.

[309] During the hearing NSPI testified that an appropriate hedging program was in front of the FAM Small Working Group and that no other party identified a need to review basis differential.

[310] NSPI has also indicated that regardless of whether their response was appropriate, the cost to hedge the basis would have cost customers more than they would have saved from putting the hedges in place. Mr. Crook stated in his Pre-filed Evidence that there are no exchange traded hedging products for Dracut. Alternatives are costly, with few market participants willing to do it for Dracut.

[311] The SBA concurred with the recommendation to conduct a study of NSPI's hedging program. However, he did not recommend setting aside the $12.8 million, stating this estimate is hypothetical. The SBA concluded though that, if it was found through the study that there is a cost associated with the imprudence, it should be disallowed.

[312] Other parties have supported Liberty's recommendations, including holding back $12.8 million until the recommended hedging policy is studied and the cost determined.

11.6.2 Findings

[313] In setting the context for its consideration of this issue, the Board is mindful of the discretionary nature of hedging practices. Hedging, by any party, has never been intended to safeguard a company or utility from all risks that might occur in the future.

[314] The Board understands that NSPI, like any other party involved in hedging practices, requires some latitude to exercise judgment in the development and implementation of a hedging strategy. In the hearing, hedging was described as an art, rather than an exact science.

[315] In fact, the decision to enter into any specific hedge or hedging strategy is akin to the purchase of insurance to protect against future losses. Like insurance, there is a wide range of hedging products that are available to parties to protect their positions. These products also come at a range of prices. In choosing any particular hedging product, it is appropriate for a party to consider the reasonable risks which might be encountered in the future.

[316] Further, the Board recognizes that it is not appropriate to rely solely on hindsight in an analysis about the reasonableness or prudence of a hedging strategy. No person can predict the future. Accordingly, if circumstances occur which result in losses as a result of a particular event or a series of events, it does not necessarily follow that the chosen hedging strategy was wrong or unreasonable. Conversely, windfalls which occur as a result of unexpected future events which were not hedged do

not make the hedging decision a brilliant one. Further, the size of any loss does not factor into the consideration of the appropriateness of a hedging strategy.

[317] The Board considers that the reasonableness of a hedging strategy must be analyzed in the context of the facts or circumstances known or reasonably expected by the person or utility at the time the hedging strategy was developed or applied.

[318] In this instance, NSPI was faced in 2010 with a long term natural gas supply contract with Shell, which was coming to an end on October 31, 2010. In replacing that contract, two significant elements of NSPI's circumstances changed. First, the price of the gas under the new contract would be based on daily prices, which are more volatile, rather than monthly prices that existed under the former contract. Second, because of the interplay between natural gas and coal prices, NSPI generally started using the natural gas in its generation fleet under the new contract, rather than selling the gas to third parties. The impact of this latter element caused NSPI to bear the increased costs itself, rather than being able to pass them to third parties purchasing the gas.

[319] The Board is satisfied that NSPI did consider the impact of the impending conclusion of the long term Shell contract. In order to protect from negative fluctuations of prices for its gas purchases, it entered into a hedging strategy which adopted swing/swaps. This would help reduce the risk of volatility in daily natural gas prices, effectively replacing the daily prices with average monthly prices which were more stable.

[320] While the swing/swaps did provide some protection to NSPI from the above noted monthly/daily price risk, swing/swaps did not, unfortunately, protect from a

significant change in the "basis differential". They are not intended to operate as a direct hedge of the "basis".

[321] However, the Board accepts the hedging evidence of NSPI that an assessment of NSPI's program in the fall of 2010 would not have reasonably uncovered the need to hedge the "basis". The Board finds that no one could have reasonably foreseen the combined series of events which led to the "basis blowout".

[322] The Board notes that NSPI had the benefit of expert advice from its consultants on the issue of hedging. As described in the hearing, both Black & Veatch and Leonard Crook have expertise in this area. Both consultants assisted NSPI with the development and implementation of its hedging practices. Black & Veatch was involved in a broad sense in its periodic review of hedging generally, while Mr. Crook was more actively involved in the decision-making process by advising NSPI in relation to gas purchases and hedging risk.

[323] The Board is satisfied that it was reasonable to retain and rely on the advice of Black & Veatch and Mr. Crook.

[324] Neither expert specifically identified a potential "basis differential" as a stand-alone risk to be hedged.

[325] The Board also notes that Liberty's position on the issue of hedging practices appeared to change from the FAM Audit report through to the hearing. Initially in its report, Liberty concluded that NSPI should have placed a hedge on the basis differential, but at the hearing their opinion seemed to change to the view that NSPI should have examined this type of hedge in anticipation of the Shell long term contract coming to an end. Given the apparent softening of Liberty's position on this issue, the

question becomes one of possible or potential imprudence, rather than actual imprudence. However, on the balance of probabilities, the Board concludes there is not sufficient evidence to warrant a finding of imprudence.

[326] After reviewing the evidence and the submissions, the Board is satisfied that NSPI could not reasonably have foreseen the events commencing in December 2010, which would lead to a significant change in the basis differential and result in the "basis blowout".

[327] Further, even if NSPI had applied a hedging strategy to deal with a potential blowout in the basis differential, the cost of purchasing such hedging products, to the extent they were available, may possibly have cost ratepayers more than the "basis blowout" itself, which NSPI addressed immediately, early in 2011.

[328] Accordingly, the Board finds that no imprudence disallowance should be imposed on NSPI as a result of the "basis blowout" in the winter of 2010-11. Consequently, no specific review is required to study what amount NSPI might have saved in the winter of 2010-11 if it had adopted a different hedging strategy.

[329] During the hearing, NSPI's hedging witness panel stated that a further examination of NSPI's hedging practices would appear appropriate on a prospective basis.

[330] On the question of a prospective study, the Board does not consider that a specific direction is necessary. The Board expects that NSPI should be continually undertaking any studies or analyses about any aspect of its fuel management practices, including hedging, if considered prudent or appropriate to lower or stabilize fuel costs.

[331] Notwithstanding the Board's findings above, it wishes to comment on one submission by NSPI on this hedging matter. In its FAM Audit Reply Evidence, NSPI suggested that "the appropriate standard for judging our hedging program is to measure its compliance with the Fuel Manual" (p. 52).

[332] However, NSPI's own expert, Peter K. Nance, of Black & Veatch, stated that the Fuel Manual does not preclude NSPI from applying a new hedging strategy:

> MS. STEWART: You would agree that the fuel manual doesn't dictate a certain strategy?
>
> MR. NANCE: No, I don't think that it dictates one strategy. I think that it has guidelines, and fairly strong ones, for certain elements of the risk -- of the hedging strategy, and I tend to -- when I think about that, what I'm thinking about are the percentages of fixed price risk, as I refer to it, that is best to be -- suggested to be managed under the program. The less -- but in -- if -- but in terms of developing an overall response, my suggestion to you would be that, yes, I believe that NSPI has the authority and the ability to do that under the manual.
>
> MS. STEWART: And so there could be different types of hedges that are entered into and still meet the requirements for fixed price management risk management ---
>
> MR. NANCE: Yes.
>
> [Transcript, October 31, 2012, pp. 868-869]

[333] Thus, in the Board's view, NSPI should not rely blindly on the express terms of the Fuel Manual to prevent it from using a new or different hedging strategy that would otherwise be reasonable in the circumstances.

11.7 FAM Audit Process

11.7.1 Evidence

[334] In its Reply Evidence, NSPI asserted that Liberty's FAM Audit is "fundamentally flawed", to the extent that the Board should reject all of the FAM Audit's conclusions and recommendations (including those which were supportive of NSPI's activities related to fuel).

[335] Among other criticisms, NSPI asserted that Liberty "has not acted in accordance with professional auditing standards"; "bases its major conclusions on a misapprehension of known facts"; its "approach, conclusions, and recommendations demonstrate insufficient knowledge and expertise in the subject matter of the audit"; and that "Liberty combines a lack of industry knowledge with a misguided approach to prudence review and a pre-existing bias against utility-affiliate relationships in order to develop a conspiracy theory that unjustly maligns NS Power, Emera, and the employees and executives of both companies": see Exhibit N-135, pp. 4-5.

[336] NSPI asserted that:

> The faulty conclusions of the FAM Audit arose from methodologies that were procedurally unfair and as such, did not meet the minimum professional standards for such an audit. Other than providing NS Power an opportunity to correct factual errors in the draft report, Liberty did not put its most serious allegations to NS Power during the course of the audit. This deprived NS Power of the chance to respond to these specifics, many of which could have been shown to be false merely by pointing to data already supplied to Liberty. Liberty's investigative methodology was flawed. It took no steps to interview the Chief Executive Officers or the Chief Human Resources Officers of NS Power or Emera, each of whom are impugned by the Report.
>
> [NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 5]

[337] In addition to its request that the entire FAM Audit prepared by Liberty be rejected, NSPI suggests that Liberty should not conduct any future FAM Audit duties:

> Despite [Liberty's] extensive involvement with the creation, implementation, and operation of the FAM, Liberty Consulting Group has conducted the FAM Audits. We respectfully submit that Liberty's deep involvement in the design and operation of the FAM precludes it from meeting the POA's requirement that an "independent firm" conduct the audit.
>
> [NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 9]

[338] Moreover, NSPI also requests revisions to the FAM Plan of Administration:

> NS Power proposes that the FAM Plan of Administration be revised in order to bring greater discipline and clarity to the audit provisions. These changes are designed to

> ensure that the Board and customers are able to obtain the benefit of a constructive and efficient review of NS Power's fuel procurement and FAM compliance, and that the Company and its employees will not experience the kind of disruption and distraction that has been experienced in this most recent audit process.
>
> [NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 82]

[339] NSPI submits that the following changes be made to the POA:

- Adopt the Institute of Internal Auditors (IIA) – International Standards as applicable to FAM Audits;
- Define auditor independence, objectivity, and competence;
- Require FAM Auditors to be selected by competitive solicitation (RFP) under the authority of the UARB, independently of NS Power or FAM participants;
- Require the audit scope to be established and finalized, and provided to NS Power and interested parties to the FAM, prior to commencement of the audit;
- Establish fixed parameters for the audit, in terms of the time to complete the audit, and for NS Power to correct errors in the draft audit;
- Require auditors to raise serious matters of concern, or significant negative recommendations, with management during the course of the audit so that management can respond and action can be taken to remedy matters as appropriate;
- Establish a standard for the anticipated cost of the audit, with an appropriate process for the UARB to approve additional costs when appropriate, and allow the utility to recover the costs of the audit and related processes, pursuant to the FAM;
- Prohibit hindsight forecasting by auditors;
- Require that any subsequent consulting work that arises from an audit recommendation must be undertaken by a consultant that is not the auditor.

[NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 83]

[340] In support of its position on the auditing standards to be applied in a FAM Audit, NSPI retained Deloitte.

[341] Deloitte drafted an audit plan and testimony that outlined potential differences between their audit approach and that of Liberty, based on a review of the final report. They observed:

- For some conclusions (presented in the section below), the report does not clearly state the evidence based on which the conclusions were drawn. We did not see evidence in the Liberty Report the Auditor conducted detailed audit procedures consistent with known standards of auditing to provide assurance to the NSUARB of compliance and use of good practices by NSPI in all cases as it relates to the FAM Audit

- The report appears to present points/conclusions relating to areas that extend beyond the scope of the FAM audit outlined under Section 5 of the POA. Circumstances/ other audit evidences that led to such extended scope will need to examined or analyzed; and
- In specific cases (e.g., conclusions on hedging program), the conclusions appear to be based on a few selected months that might have had issues rather than the whole audit period or based on a randomly selected sample. It is important to examine if the same conclusions would be drawn on a random sample; Circumstances or selection criteria which led Liberty to form opinions based on specifically selected samples needs to be better understood to validate the conclusions.

[Exhibit N-131, p. 3]

[342] NSPI had Deloitte, Ms. Medine and Mr. Reed testify to auditing standards, with Deloitte recommending the Institute of Internal Auditors Standards and the US Government Accountability Office Auditing Standards, and others referring to the National Association of Regulatory Utility Commissions (“NARUC”) standards. During its testimony, Deloitte agreed the NARUC standards would also be appropriate:

> MS. RUBIN: Would you concur that the NARUC guidelines would also offer suitable guidelines to the preparation of a FAM Audit?
>
> MR. LOBAREC: Yes, I think that’s a reasonable question and I would agree, it could. It’s more about whether or not we go from assertion to specific ordered steps and then provide evidence that’s sufficient against those steps to reach a conclusion. Any of the ordered standards could lead you to that as long as those steps are followed in concert.
>
> [Transcript, October 31, 2012, p. 820]

[343] NSPI experts also testified they had concerns related to Liberty’s compliance with auditing standards, referring to concerns with Liberty’s Audit Report with respect to the NARUC standards. Ms. Medine stated:

> The FAM Audit and the FAM Audit Report do not meet industry standards with respect to guidelines established by the National Association of Regulatory Utility Commissioners (NARUC), the U.S. General Accounting Office (GAO), and other entities in a number of material ways. The most significant issues are as follows:
>
> - Material areas of the FAM Audit were not conducted by individuals that have sufficient expertise and relevant experience.
> - Confidential information was disclosed during the course of the FAM Audit.
> - The FAM Audit Report was not objective and did not have a balanced tone.

- Liberty failed to support all material findings with relevant evidence.

[Exhibit N-133, pp. 2-3]

[344] In its FAM Audit Reply Evidence, NSPI placed particular emphasis on the Deloitte opinion, stating:

> Deloitte's opinion is important for the Board to consider. Deloitte is a global auditing and consulting organization with the highest reputation for professionalism and integrity. The firm assigned accomplished international experts to the review of the FAM Audit. Deloitte identifies and applies established professional auditing standards. The Deloitte assessment identifies what NS Power respectfully suggests are serious gaps in the Liberty Report.

[NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 81]

[345] The Board notes, as did Liberty in its Reply Evidence, that despite NSPI's characterization of Deloitte's evidence, nowhere did Deloitte describe any possible gaps in Liberty's audit as serious or significant in any way.

[346] Ms. Medine claimed other utilities have encountered similar problems with Liberty audits.

[347] However, Board Counsel witness Robert E. Curry, Jr., presented a different opinion. Mr. Curry is experienced in the field of utility regulation, including as a former Commissioner of the New York Public Service Commission. Based on responses from senior officials in 11 State regulatory entities, and based on his own personal experience with Liberty, he stated:

> All of the respondents spoke highly of: Liberty's professionalism; the value Liberty's reports added to the regulatory process for both the utility and the regulator; its attention to keeping Staff of the client informed of its progress; the general interaction with the utility being audited (in spite of differences in views of the subject matter of the review); and, its overall effectiveness. No respondent reported any instance of prejudice or bias either for or against the utility or its regulator. "Tough but fair" was a term used by several commentators. …

[Exhibit N-168, p. 5]

[348] In Board Counsel's questioning of the NSPI witness panel, he referred the panel to the views of National Grid about Liberty. National Grid delivers electricity to approximately 3.3 million customers in the U.S. Northeast. In a news release about a five month independent review of its accounting systems and practices, National Grid stated:

> We engaged Liberty because of their reputation as being both thorough and independent. We wanted a report that would take a critical look at those areas where we need to improve, and this will help guide us going forward.
>
> …
>
> The company will share the report shortly with regulators in its various US operating areas. Liberty Consulting is a nationally recognized leader in providing independent reviews of regulated businesses. Its report is based on hundreds of data requests and employee interviews, site observations of systems operations, on-site document reviews, transaction testing and numerous working sessions
>
> [Exhibit N-207]

[349] The NSPI witness panel did not challenge National Grid's view of Liberty.

[350] The Province also suggested that some revisions may be appropriate for the documents relevant to the FAM Audit:

> The issues raised during the FAM audit suggest that it may be appropriate to consider a review of some of NSPl's guiding documents. It may be advisable for the FAM small working group to consider whether the hedging practices in NSPl's Fuel Manual should be assessed. It may also be appropriate to consider whether NSPl's Affiliate Code of Conduct should be reviewed to consider whether, and to what extent such a document can address NSPl's non-transactional relations with its affiliates (i.e., the extent to which NSPl's actions or inactions may or may not be influenced by the activities of its affiliates even when NSPI is not engaged in specific transactions with them).
>
> [Province Closing Submissions, November 23, 2012, para. 26]

[351] However, the Province was concerned with the tone of the debate respecting the audit, including NSPI's response:

> NSPl's FAM Plan of Administration ("POA") is also ripe for review. In many ways, the level of debate in this case over the FAM audit, a critical element of a successfully functioning NSPI FAM, was unfortunate. From NSDOE's perspective, the tone set by the FAM report audit could have been viewed negatively. Of course, tone can be difficult to

infer from the printed word, and sometimes tone can be imputed when it is not intended. Particularly if one is not engaged in actual dialogue.

Regardless of how it viewed the FAM Audit Report, NSDOE respectfully submits that NSPI's response did not help matters. NSPI apparently took the criticism as cause for war. Rather than responding quickly and confidently - it defensively called forth a battalion of high-priced experts to wage a war of words. And the FAM process has suffered collateral damage.

[Province Closing Submissions, November 23, 2012, paras. 27-28]

[352] The CA retained David P. Vondle to make recommendations with respect to the FAM Audit process. He is a partner with SAGE Management Consultants LLC, with 25 years of management consulting experience that includes leading 31 management audits. Mr. Vondle observed the NSPI response to the Audit was unprecedented, stating:

- With few exceptions, NSPI attacks conclusions and recommendations rather than findings (facts).
- NSPI admits it did not make factual corrections when it had the chance prior to the publication of the report. Normally, utilities take this opportunity to try to influence the conclusions and recommendations as well.
- NSPI attacks the NSUARB for hiring Liberty to do the FAM audit after Liberty acted as an extension of the NSUARB in putting the FAM process in place.
- The NSPI complaint about not having the scope of the audit is NSPI's own fault. NSPI could have insisted on having the work scope, work plan and schedule before beginning its participation in the audit. Also, the Liberty FAM Audit Report for 2010-2011 had the same chapters as the 2009 Report, with the exception that Economic Dispatch and Power Purchases and Sales were divided into two separate chapters for 2010-2011. (Tables of Contents) The 2009 Report had multiple negative conclusions and one quantification of excess cost, $220 thousand, which could have been avoided by NSPI not granting a quantity flexibility option and more diligently enforcing the maximum volume limits of solid fuel contracts. (Page VI-21). The 2009 Report also recommended retroactive adjustments to the calculation of FAM carrying costs, but did not quantify the amount. (Page X-13) NSPI should not have been surprised by the scope of the 2010-2011 Audit.
- On the FERM staff turnover issue, the NSPI Reply Evidence confirms the Liberty finding that the entire FERM senior management team plus the next level-down Solid Fuels Scheduling and Logistics Coordinator turned over in the 2010-2011 period and that two of them left for affiliate positions. In the two-year period, FERM lost 10 of 18 employees and downsized to 16 positions – only eight employees were added. This is a lot of turnover in a small unit by any measure. At the end of the two year period, only eight of 18 original employees remained and none of the senior managers.
- The NSPI ad hominem attacks against Liberty are unprecedented in my experience.

- I am not familiar with Deloitte participating in the management audit or fuel audit business. I cannot recall them bidding or winning a Commission sponsored study. Perhaps they do in Canada or Europe. For example, the New Jersey Board just pre-qualified a set of seven management audit firms for the next round of management audits. Deloitte was not one of them. However, Liberty was one of the selectees.

[Exhibit N-169, pp. 8-10]

[353] Mr. Vondle does support potential changes to the Plan of Administration, however not as put forward by NSPI, indicating that some of NSPI's requests are "unusual" or "odd".

[354] The CA submitted in its Closing Submissions that it "has seen no evidence to support NSPI's attack on Liberty" (p. 8).

[355] The SBA submitted that there is no basis to reject the FAM Audit's findings or to dismiss Liberty as the auditor. He also noted NSPI's failure to respond to the FAM Audit as contemplated in the POA:

> SBA argues there has been no substantive evidence filed or testimony heard at this F AM Audit hearing which supports the removal of Liberty as a FAM Audit Consultant. The uncomplimentary and unprofessional exchange of communication between Liberty and NSPI and the consultants is unfortunate. However, the SBA argues this does not establish that Liberty did not prepare an Audit report in an expert and detailed manner and they did forward a copy of the draft Audit report to NSPI for their review and comments; however, the reply that was forthcoming was to the effect, it was not worth replying to and the matter will be responded to through litigation at the FAM Audit hearing. SBA argues the long standing position of the Board was for the Board Consultant to prepare a draft report to be sent to NSPI for review and comments before finalization. It is undisputed that Liberty did send a draft audit report to NSPI for comments.
>
> SBA argues there was ample opportunity before the time the report was filed, even up to the hearing, to attempt to negotiate areas of concern. Unfortunately, that did not occur.
>
> …

> Accordingly, SBA argues there was no substantive evidence filed by NSPI to have Liberty removed as auditor nor is there substantive evidence to request a new audit by a different auditor, and accordingly, this Board should reject NSPI's request in that regard and deal with the Audit Report on its merits.
>
> [SBA Closing Argument, November 23, 2012, pp. 7-8]

[356] Avon also expressed its approval of the Audit conducted by Liberty, and its confidence in Liberty:

> It appears to the Avon Group that upon finding that the Liberty Audit continued to press NSPI on certain issues, particularly related to the natural gas market and affiliate relationships, NSPI embarked on a strategy which focused on reputation management for NSPI through press conferences, media releases, direct contact with customers, expert evidence, overzealous confidentiality redactions and a concerted attack on the motives and credentials of the Liberty staff who performed the Audit, culminating in a recommendation that the entire Audit be rejected and Liberty prohibited from ever performing another audit of NSPI for the Board.
>
> At the end of the day, and after all the noise, perhaps what was most telling is that despite the massive pre-hearing efforts to undermine the expertise of the Liberty witnesses, when given the opportunity during the hearing, NSPI did not ask one question to challenge the expert qualifications of the Liberty witnesses. Not one.
>
> The Avon Group relies very much on the experience and expertise of Liberty and while there may be other auditors who could accomplish what is done by Liberty, there would be a steep learning curve which is neither efficient nor practical. It seems to the Avon Group that with Liberty's historical experience with NSPI comes greater knowledge regarding "problem areas" and the questions to ask. If Liberty ruffles feathers, so be it.
>
> As noted by the Board in its decision on confidentiality of the FAM Audit, the focus in regulating NSPI is to examine whether NSPI's costs are prudently incurred. That goes to the heart of the regulatory compact, and the FAM is an integral component of the costs which NSPI seeks to recover. A meaningful, transparent audit is an essential part of the FAM. The Avon Group has seen nothing in the Liberty Audit Report or its dealings with Liberty that suggest that the Audit Report is so fundamentally flawed that it should be rejected in its entirety or declared "invalid" as urged by NSPI.
>
> In the end, at best, NSPI's strategy in responding to the Audit was distracting; at worst, it served to frustrate the process. The Avon Group would strongly urge the Board in its decision to address not only the specific recommendations made in the Audit but also the Board's expectations regarding meaningful participation in the Audit process as a requirement for continued enjoyment of a FAM so as to ensure that these tactics do not interfere with the next audit process.
>
> [Avon Final Submissions, November 23, 2012, paras. 33-37]

[357] Further, two Intervenors specifically noted their disappointment with the fact that NSPI only provided their opinion on the remaining recommendations in the FAM Audit in Undertaking U-22 filed at the very end of the hearing.

[358] The Province stated:

> A response to the FAM Audit report, like the one seen in NSPI's response to Undertaking U-22 should have been a first response, and not dragged out during the last days of the hearing. …
>
> The FAM POA should be reviewed and revised to ensure that stakeholders receive appropriate responses to a FAM audit from NSPI, as soon as possible, and at a very early stage in the proceeding.
>
> [Province Closing Submissions, November 23, 2012, paras. 29-30]

[359] Avon also expressed its concern with the lateness of NSPI's position on the remaining recommendations in the Audit report:

> By failing to respond substantively to the draft Audit, and by taking the position that the entire Audit should be rejected by the Board, NSPI failed to provide key information to Liberty, the Board and stakeholders. Indeed, the Utility never indicated which of the 2012 Audit recommendations it accepted. This information was not provided until the last day of evidence in response to an undertaking given during the hearing.
>
> Of 42 recommendations, NSPI apparently agrees with 27. Some of the recommendations with which NSPI does not agree were raised in a substantive way through this hearing, but others have not been addressed at all. NSPI's failure to provide this basic information in a timely fashion has impeded the Board and Intervenors from properly examining NSPI's position with respect to the 2012 FAM Audit.
>
> [Avon Final Submissions, November 23, 2012, paras. 31-32]

11.7.2 Findings

a) Auditing Standards

[360] The Board will first address the issue of auditing standards. While NSPI cross-examined the Liberty witness panel at the hearing with respect to its evidence related to NSPI's fuel related activities (including the activities noted above which attracted disallowances), counsel for NSPI did not challenge or question any of Liberty's witnesses on their professional qualifications, nor did NSPI counsel cross-examine the Liberty witness panel on the auditing standards or methodology applied by Liberty in the FAM Audit.

[361] NSPI relied on Deloitte's evidence. However, the Board notes that while Deloitte is a reputable auditing and consulting firm, the scope of its engagement in this matter was limited.

[362] First, Deloitte was not engaged to express an opinion on the correctness of Liberty's FAM Audit opinions:

> MS. RUBIN: And you were engaged to identify deficiencies in the report rather than provide an opinion on the correctness of Liberty's opinions?
>
> MR. LOBAREC: We were engaged to identify potential differences, based on the way we would do our work and the way we're able to observe that it was done in the report we were provided from Liberty.
>
> [Transcript, October 31, 2012, p. 814]

[363] Second, even though Deloitte was engaged to identify "differences" in the Liberty FAM Audit Report, Mr. Lobarec, Deloitte's national leader for energy and resources across Canada, acknowledged in his testimony that they did not review any of Liberty's working papers, nor did Deloitte even interview anyone at Liberty:

> MS. RUBIN: …And is it fair to say that the -- even at the end of your work, you were only able to identify some potential differences in approach?
>
> MR. LOBAREC: That is correct. As we've said in our report, there may be factual evidence contained in work papers or other areas that we were not able to observe that would form a more reasonable basis for reaching some of those conclusions.
>
> MS. RUBIN: Right. And the reason for that, identifying potential differences, is because you only took a high-level review of the Liberty report; correct?
>
> MR. LOBAREC: It's probably more because we're engaged to develop an audit plan. So it's only based on the way that we would do the work and the factual basis or evidence that we would require against a report. So I hope that answers your question.
>
> MS. RUBIN: But what you did was a high-level review of the Liberty report?
>
> MR. LOBAREC: We were only able to read the report, that's correct.
>
> MS. RUBIN: Right. You didn't review any supporting work papers?
>
> MR. LOBAREC: No, we don't have access to that.
>
> MS. RUBIN: Okay. And did you interview anyone at Liberty?

> MR. LOBAREC: No.
>
> [Transcript, October 31, 2012, pp. 814 – 816]

[364] Notably, Mr. Lobarec of Deloitte also admitted that none of the individuals involved in the preparation of Deloitte's evidence had, in fact, ever carried out a fuel management audit on behalf of a regulator:

> MS. RUBIN: Were there -- how many people were involved in the preparation of the Deloitte evidence?
>
> …
>
> MR. LOBAREC: It is 10.
>
> MS. RUBIN: It's 10, okay. Now, of those 10, is it correct that none have performed fuel management audits on behalf of a regulator?
>
> MR. LOBAREC: In -- yes, that's correct.
>
> [Transcript, October 31, 2012, pp. 816-817]

[365] Finally, Mr. Lobarec acknowledged that there is no single standard for an auditor conducting a fuel management audit:

> MS. RUBIN: …Now, would you agree that there's not one single correct approach to a fuel management audit?
>
> MR. LOBAREC: Yes, it is open to interpretation. The adoption of standards and the way it's done varies. I do agree with that.
>
> [Transcript, October 31, 2012, p. 814]

[366] In light of the above, the Board assigns little weight to Deloitte's evidence with respect to the issues in this FAM Audit.

[367] Ms. Medine was very critical of Liberty's auditing methodology.

[368] As noted earlier in this Decision, the Board gives little weight to Ms. Medine's evidence.

[369] This is not Liberty's first FAM Audit of NSPI. The 2010 Audit conducted in relation to the 2009 fuel related activities was met with general agreement by NSPI. At that time, NSPI did not express any concerns with the auditing standards applied by Liberty.

[370] Further, NSPI's assertions that Liberty has an "insufficient knowledge and expertise in the subject matter of the audit" and that it has a "lack of industry knowledge" is not borne out by the evidence. In this respect, the Board accepts the evidence of Mr. Curry, whose evidence was not challenged by NSPI, that Liberty possesses an excellent reputation with at least 11 regulatory commissions in the U.S., both in terms of Liberty's professionalism and its effectiveness in the conduct of audits.

[371] It is also instructive that NSPI did not cross-examine any member of the Liberty witness panel about their professionalism, qualifications or expertise.

[372] The Board is aware of the NARUC guidelines. On the basis of the evidence before it, the Board is satisfied that Liberty's FAM Audit is consistent with the NARUC guidelines. The FAM Audit was also conducted in a manner consistent with the process contemplated under the POA approved by the Board.

[373] In addition, it is noted that NSPI's customers were satisfied with Liberty's work on this file. The Board places significant weight on the support given to Liberty by the Intervenors representing most customer classes. The CA, the SBA and Avon all support Liberty in its conduct of the present audit and in future audits. It is clear that the present audit was conducted in a manner which met the expectations of these customer classes.

[374] The Board concludes that Liberty's FAM Audit followed appropriate auditing standards.

b) Future Audits

[375] The second issue considered by the Board relates to future audits. NSPI made a number of requests for changes to the POA and to restrict the engagement of Liberty on future FAM Audits.

[376] The Board notes that the issue of POA amendments or future audits was not on the Final Issues List approved by the Board for this proceeding.

[377] On this point, the Board indicated during the hearing that it would be more appropriate to review all aspects of the FAM in a separate proceeding where the FAM and all other issues related to it (including the POA) can be examined, rather than in a piecemeal fashion. The Board maintains its view on this issue.

[378] Accordingly, the Board makes no directive at this time with respect to possible changes to the POA or future FAM Audits.

c) NSPI's Response to the Audit

[379] Another issue which arose out of the evidence and submissions respecting the audit process relates to NSPI's response to the draft Audit Report submitted to it by Liberty. The Board shares many of the Intervenors' concerns.

[380] NSPI asserts that the nature of the allegations in the Audit Report justified its decision not to comment to Liberty on the draft Report and, instead, to launch a strong reply to the Report as part of the GRA hearing, including the engagement of numerous expert consultants.

[381] On the other hand, the CA, SBA, Avon, and the Province, submit that NSPI, in failing to respond to the draft Audit Report, acted contrary to the FAM Audit process contemplated in the FAM POA. Moreover, they assert that NSPI's failure to disclose material information in the hearing process, including in its FAM Audit Reply Evidence, in its Responses to Information Requests from Intervenors, and even in its testimony under cross-examination by the Intervenors, frustrated the FAM Audit process.

[382] These Intervenors are represented by experienced counsel who, except for the SBA, have been involved in the proceedings leading to NSPI's request for a FAM and the adoption of the FAM by the Board. NSPI's strategy in responding to the FAM Audit fell far short of the expectations of these counsel.

[383] As noted earlier in this Decision, the POA provides that NSPI would be provided with a draft Audit.

[384] When provided with the draft FAM Audit in June 2012, NSPI elected not to offer any comments to Liberty. It is clear from the terms of the POA that the final FAM Audit report is to "evolve" from the draft Report. This clearly contemplates input from NSPI about the contents of the draft Report. The POA provides that NSPI has 30 days to comment. Liberty specifically requested NSPI's comments. The prior 2010 FAM Audit had proceeded in this fashion.

[385] In its evidence, NSPI claimed that it did, indeed, respond to the draft Audit Report, referring to a reply email from its counsel Rene Gallant on June 24, 2012. However NSPI chooses to characterize Mr. Gallant's email, the Board finds that it

amounted, in effect, to a non-response on the substantive issues in the draft Report. Further, it was not the type of response contemplated under the POA.

[386] In choosing this course of action, NSPI did not provide Liberty with relevant information which might have caused Liberty to change its findings and recommendations, including possibly withdrawing some of the proposed disallowances. Further, if NSPI had discussed its concerns with Liberty about the tone of the draft Report, or about some of the observations in it, the language of a final Audit Report might have been more restrained. No one will ever know because of NSPI’s response.

[387] NSPI’s tactical response to the draft Audit Report contributed to further difficulties in the audit process. In accordance with the POA, Liberty did provide NSPI with a draft Report of its findings. NSPI’s initial non-response led Liberty to file the draft Audit Report with the Board, in effect, becoming Liberty’s final FAM Audit Report.

[388] In fuel management or prudence audits, the Board expects the auditor to report disputed or unresolved issues to the Board. Faced with NSPI’s non-response to the draft Audit report, it was entirely reasonable for Liberty to then file its findings with the Board.

[389] Based on its review, the Board finds that NSPI's decision to ignore the draft Audit Report did not comply with the terms of the POA and its related conduct was unreasonable. Moreover, the Board notes that all of the auditing standards or guidelines cited by Deloitte, Ms. Medine, or Mr. Vondle contemplate the audited party reviewing a draft audit report and responding to any deficiencies that should be addressed. In this case, NSPI decided, for whatever reason, to forego the opportunity to respond and to challenge all of Liberty's findings and recommendations in the hearing

(even those findings which it later acknowledged it agreed with in Undertaking U-22). In so doing, the Board concludes that NSPI's conduct was contrary to what would have been reasonably expected under the POA. It certainly was contrary to the reasonable expectations of the Board and the Intervenors. NSPI also acted in a manner which is not consistent with the spirit and intent of audits generally, including fuel management or prudence audits.

[390] Further, NSPI's course of action distracted and misdirected all parties in this proceeding from addressing some of the other important issues in the hearing. NSPI's course of action had the effect of wasting scarce resources, in terms of time, money and human resources, for all parties.

[391] At this point, the Board notes that Liberty bears some of the responsibility for the acrimonious relationship which developed over the course of the FAM Audit process between NSPI and its FAM auditor. Some of Liberty's language was provocative in a way it did not have to be. In retrospect, the Utility's response might have been more tactful and reserved if Liberty had adopted a more measured tone in its criticism of NSPI's FAM activities. This would have resulted in a more productive Audit process.

[392] Nevertheless, the tone used by Liberty in a few of its findings is no excuse for the nature of NSPI's comments respecting the FAM Audit Report. NSPI's comments and non-responsive strategy only served to escalate the rhetoric and to hinder the efficient review of the Audit Report by the Intervenors and the Board.

[393] In making these findings, it is not the Board's intention to suggest that NSPI should not challenge any finding or recommendation by a fuel management

auditor, in a hearing if necessary. However, before it embarks on such a challenge, it has a responsibility under the POA, and to its ratepayers, to provide its comments in a timely fashion on a draft Audit Report delivered to it by the auditor. Such a response would help to resolve or narrow the issues identified during the Audit and would have allowed the Intervenors and the Board to conduct an efficient review of the Audit Report.

[394] In the future, the Board expects NSPI to conduct itself in accordance with the intent and the terms of the POA, including providing a meaningful response to the draft Audit Report.

d) Non-contested Recommendations in the Audit Report

[395] Finally, the Board is concerned with NSPI's failure to comment at an early stage with respect to the remaining recommendations in the FAM Audit. While it initially issued a blanket dismissal of the entire Audit Report (including the findings supportive of NSPI's fuel related activities), it ultimately agreed, at the end of the hearing, in an Undertaking requested by Avon, to identify which recommendations it agreed were reasonable. Initially, counsel for NSPI sought to limit the scope of the undertaking and questions about the other recommendations in the Audit Report. In Undertaking U-22, filed at the conclusion of the hearing, NSPI identified the recommendations it agreed with and which ones it did not. Interestingly, however, NSPI stated in its response to Undertaking U-22, "NS Power makes no comment on the conclusions in the Liberty report." Again, NSPI's approach unnecessarily lengthened the hearing and resulted in the inability of the Board and the Intervenors to delve into an efficient and meaningful assessment of the substantive issues identified in the FAM Audit.

[396] Despite its initial blanket rejection of all Liberty's FAM Audit recommendations, NSPI appeared to adopt a more conciliatory tone after the hearing was completed. In its Closing Submission, NSPI stated:

> … NS Power's response to Undertaking U-22 outlines NS Power's position on each of the recommendations contained in the Liberty audit report. Out of 42 recommendations, NS Power agrees with 27 recommendations. At least 15 of these 27 Liberty recommendations are items that had already been undertaken by NS Power...or that are existing practices or plans of the Company...
>
> [NSPI Closing Submission, November 23, 2012, p. 27]

[397] In its Reply to Closing Submission, NSPI asked the Board for the "rejection of the disputed conclusions and recommendations from the FAM Audit Report", offering no further comment on the remaining recommendations.

[398] Counsel for Avon noted that the late filing of such information deprived the Intervenors of the opportunity to conduct a meaningful assessment of the issues and, indeed, frustrated the conduct of the FAM Audit process itself. The Province, which typically takes no position in GRA proceedings, expressed similar concerns.

[399] In the future, the Board expects NSPI to outline, no later than in its Reply Evidence, which audit findings or recommendations it agrees with and which it does not.

11.8 FAM Small Working Group

[400] Another issue arose out of the FAM Audit hearing which the Board considers should be addressed. It is apparent that NSPI has a different view than the Board about the role of the various participants in the FAM Small Working Group ("SWG").

[401] In a few instances related to its gas hedging practices, NSPI indicated its reliance on the SWG for its decisions or course of action.

[402] For example, with respect to the losses incurred by NSPI as a result of the "basis blowout" commencing in December 2010, NSPI appeared to place some of the responsibility for its decisions on gas hedging strategies on Liberty and other members of the SWG:

> Liberty is also a participant in the FAM Small Working Group. Minutes of the FAM SWG for the six months leading up to the basis blowout period make no reference to any comment by Liberty, or by any other stakeholder, identifying the need for a study to examine the potential for reducing fuel cost volatility by hedging the basis differential.
>
> [NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 55]

[403] Similarly, in its Closing Submission, NSPI stated:

> As Mr. Bennett and Mr. Sidebottom explained, the Black & Veatch study was discussed with stakeholders during FAM Small Working Group (SWG) meetings, and the results of the study were provided to the FAM SWG. No concerns or objections were raised about the study or whether it was sufficiently comprehensive or focused. Liberty also reviewed the study and agreed with the study conclusions in a December 10, 2010 memo to NS Power. Despite Liberty providing its written comments just days before the December 2010 "basis blowout", Liberty provided no complaint or criticism that the basis differential risk had not been addressed nor that additional focused study work should be done on basis differential or any other component of risk. Clearly Liberty did not, at the time, see basis differential as a significant risk any more than NS Power did. …
>
> [NSPI Closing Submission, November 23, 2012, p. 45]

[404] NSPI also appeared to implicate Liberty and the SWG in the "development" of the Fuel Manual:

> The Fuel Manuel is a highly prescriptive document, developed in close consultation with stakeholders and Liberty, and approved by the Utility and Review Board. NS Power believes the appropriate standard for judging our hedging program is to measure its compliance with the Fuel Manual.
>
> [NSPI FAM Audit Reply Evidence, Exhibit N-135, p. 52]

[405] The Board wishes to reiterate that the role of the SWG, or any of its individual participants, is not to manage NSPI's fuel related activities. The responsibility for such activities lies squarely on NSPI and not on any other SWG participant. Accordingly, NSPI should not seek to cast any responsibility on the participants for

particular actions taken by NSPI or to reproach the other participants for not suggesting an alternative course of action.

11.9 Remaining recommendations in FAM Audit

[406] As noted earlier in this Decision, NSPI did not initially indicate in its Reply Evidence which findings or recommendations of Liberty it agreed with. On the last day of the hearing, in an Undertaking requested by Avon, NSPI agreed to provide an Undertaking to the Board outlining which recommendations it rejects, which it accepts, and which it has implemented. In the latter case, NSPI was to outline its action plan.

[407] NSPI filed Undertaking U-22 on November 9, 2012. As noted by NSPI in its Closing Submission, it agrees with 27 of 42 recommendations. However, Avon states that NSPI's late filing of this information has impeded the Board and Intervenors from "properly examining NSPI's position with respect to the 2012 FAM Audit".

[408] The Board directs that NSPI proceed with the implementation of the recommendations it has agreed with in Undertaking U-22. In the instances where NSPI has not provided an action plan for the recommendations with which it agrees, it is directed to file its implementation plans by February 28, 2013.

[409] In the case of recommendations which are not agreed to by NSPI, it is to file a detailed explanation why it does not agree. This is also to be filed by February 28, 2013.

[410] The Intervenors will then be permitted to provide their comments to the Board by March 29, 2013, with respect to any of the remaining recommendations.

11.10 Disallowed Costs related to the FAM Audit

11.10.1 Evidence

[411] Earlier in this Decision, the Board reviewed instances in which NSPI undertook a course of conduct which, the Board considers, was contrary to what would have been reasonably expected under the FAM POA.

[412] NSPI repeatedly refuted a recommendation by Liberty to pursue concerns with the NEB and potential sellers of natural gas about the state of the Maritimes natural gas market. Moreover, Liberty's recommendation was, in effect, summarily dismissed by NSPI, who even went as far as to assert that Liberty did not understand the regulatory regime in Canada and that this was a basis for concluding that Liberty was inept and unqualified to perform its FAM auditing duties.

[413] However, on the very last day of the hearing, the NSPI witness panel, primarily Mr. Janega, revealed that NSPI had indeed carried out a course of action over the past few years which had actually taken into account Liberty's concern on the state of the natural gas market in the Maritimes. Of particular concern to the Board, in terms of the FAM Audit generally (including the administration of the POA), is the fact that NSPI, notwithstanding its course of action to the contrary, denied that Liberty`s concern was in any way legitimate or worthy of any action.

[414] NSPI maintained its dismissal of Liberty`s concern during the period leading to the release of the FAM Audit, as well as in its FAM Audit Reply Evidence, in its Responses to Information Requests from the Intervenors, and in its sworn testimony in cross-examination by these same Intervenors. NSPI's revelation about its actual course of action only occurred on the very last day of the hearing during questioning by Board Counsel.

[415] NSPI's course of action distracted and misdirected all parties in this proceeding (and the public) from the real issue which should have been addressed at the hearing about the natural gas markets. Moreover, NSPI's course of action had the effect of wasting scarce resources, in terms of time, money and human resources, for all parties, notably those of the Intervenors who participated in this proceeding, including experienced legal counsel and, likely in some cases, their expert consultants. This conduct resulted in increased costs for all Intervenors, including those representing most customer classes served by the Utility.

[416] The lack of disclosure by NSPI was not restricted to the matter involving the NEB.

[417] First, it was not until the hearing that NSPI disclosed the true extent of its response with the circumstances surrounding the withdrawal of Bid A by the counterparty, as described earlier in this Decision. It was not until her testimony that Ms. Trenholm, under cross-examination, revealed NSPI's actual reaction following those events. NSPI, in fact, voiced its strong displeasure with the counterparty, but decided that its interests would best be served in the long term by preserving the relationship. However, NSPI's actions and reasoning on this issue were not fully disclosed to Liberty or the Intervenors until the hearing.

[418] Another instance of inadequate disclosure arose in the context of the Lingan derate matter. Liberty had proceeded with its analysis of the issue using NSPI's schedule of different coal blends used at Lingan over the relevant period. However, during their cross-examination by NSPI, the Liberty witness panel was presented with a different schedule of coal blends used over the same time span. This required Liberty

to reconsider its analysis in an Undertaking. It is curious that, later in the hearing, when asked about the revised schedule by Board Counsel, Marie Thomas, of the NSPI Fuel Panel, was required to be briefly excused by the Board to confirm whether the revised schedule was, in fact, the correct schedule. Fortunately, her records matched the revised schedule, but what appeared to be confusion in communication among NSPI's different representatives was disconcerting to the Board.

[419] Yet another example of poor disclosure, for whatever reason, was in relation to the gas hedging issue and the Black & Veatch report. While it was clear from a plain reading of the Black & Veatch report that the issue of the "basis differential" could not reasonably be seen as a specific issue within the scope of the engagement, NSPI, in its testimony at the hearing, specifically its Fuel Panel, nonetheless characterized the Black & Veatch report as dealing directly with the issue. The Company had not previously disclosed its reliance on that report specifically for that purpose, even though it became a central theme of its testimony at the hearing on the hedging issue.

[420] The second issue which causes great concern to the Board is NSPI's failure to follow the process contemplated by the FAM POA for the development of the FAM Audit report itself.

[421] As noted earlier in this Decision, when provided with the draft FAM Audit in June 2012, NSPI elected not to offer any comments to Liberty. It is clear from the express terms of the POA that the final FAM Audit report is to "evolve" from the draft report. This clearly contemplates input from NSPI about the contents of the draft

Report. The prior 2009 FAM Audit had proceeded in this fashion. The POA provides that NSPI has 30 days to comment.

[422] In choosing this course of action, NSPI did not provide Liberty with relevant information which might have caused Liberty to change its findings and recommendations, including possibly withdrawing some of the proposed disallowances.

[423] On a related point, NSPI initially dismissed all the other FAM Audit findings and recommendations which were supportive of the Utility's fuel related activities or those which NSPI later indicated, in Undertaking U-22, that the Utility agreed with.

[424] Again, the result of NSPI's conduct, in failing to comment on the draft Audit report, is that it unnecessarily lengthened the hearing and wasted the time, money and effort of the Intervenors in this proceeding, as well as Board Counsel.

[425] In its Closing Submissions, the CA specifically requested that the Board sanction NSPI as a result of its conduct in responding to the FAM Audit:

> In its pre-filed evidence and throughout much of its testimony before the Board, NSPI aggressively challenged Liberty's experience, qualifications, ethics, and independence.
>
> Put simply, the Consumer Advocate has seen no evidence to support NSPI's attack on Liberty. Furthermore, the Consumer Advocate sees NSPI's attack as offensive to the regulatory process itself. Clearly, a mature utility needs to understand the difference between disagreeing with an auditor's recommendations and a baseless assault on the auditor's reputation.
>
> In such circumstances, where a utility initiates and maintains baseless attacks on auditors appointed by the regulatory body, there ought to be a consequence for the utility.
>
> An obvious consequence would be to assess some portion of the costs of the hearing which have been generated as a result of NSPI's intransience and to have them borne by the company and its shareholders. The assessment could consist of either a reduction of the costs that NSPI could otherwise recover and/or an assessment of a portion of the costs incurred by the Board and intervenors against NSPI. The assessment could be by way of a lump sum set by the Board in consideration of all the particular circumstances.
>
> [CA Closing Submissions, November 23, 2012, p. 8]

11.10.2 Findings

[426] The Board is responsible for the general supervision of NSPI under the *Public Utilities Act*. Section 18 provides:

> **Supervision of utility by Board**
> **18** The Board shall have the general supervision of all public utilities, and may make all necessary examinations and inquiries and keep itself informed as to the compliance by the said public utilities with the provisions of law and shall have the right to obtain from any public utility all information necessary to enable the Board to fulfil its duties.

[427] While the CA requests that NSPI be sanctioned for its conduct generally, the Board considers that any such sanction should relate to specific instances where NSPI has showed imprudence or ignored direction from the Board.

[428] In this respect, the Board expects NSPI to comply with its Decisions, Orders and directives, including its oversight procedures such as the FAM Audit and the POA. In the Board's opinion, NSPI's conduct in relation to the NEB issue and the aggressive pursuit of gas supplies, and its decision not to comment on the draft Audit Report, were both unreasonable and inappropriate. Further, as noted above, its conduct on these specific points resulted in unnecessarily extending the length of the hearing and wasting the time, money and effort of the Intervenors and Board Counsel.

[429] In these circumstances, the Board finds that a sanction is warranted as against NSPI. In accordance with its jurisdiction under s. 18 of the *Public Utilities Act*, as well as its mandate under the *Act* generally, the Board concludes that a disallowance of $2 million is appropriate and it so orders.

[430] In determining the disallowance of $2 million, the Board has relied, in part, on its evaluation of unnecessary costs incurred by the CA, SBA and the Board as a

result of NSPI's response to this FAM Audit. Likewise, NSPI, itself, would also have incurred unnecessary costs.

11.11 Implementation of the FAM disallowances

[431] As a result of the Board's findings earlier in this Decision, disallowances have been made as against NSPI with respect to its imprudence and its conduct in relation to directives by the Board. These disallowances must now be implemented in this Decision.

[432] As noted earlier, the Board has approved the GRA Agreement. Further, in a separate proceeding, by Order issued December 10, 2012, the Board has approved the 2013 FAM Actual Adjustment (AA) and Balance Adjustment (BA) recovery values. Both of these approvals were made subject to any further adjustment arising from this Decision.

[433] There are several options to implement the disallowances.

[434] The SBA recommended as follows:

> SBA points out while the overall amount of imprudence disallowance amounts are small as a percent of revenues they still maintain an important monetary issue for small businesses of Nova Scotia. Small businesses have felt the hard impact of the current economic climate. Increases in electric rates associated with raising [sic] NSPI costs and the losses of large customer loads will present the SBA's constituents with yet [another] straw to add to a burdened back. SBA suggests that the manner to return the benefits of any disallowance is to first go to offset or wipeout the 2012 FAM AA adjustment. This would reduce the specter of looming future rate increases and the potential for the timing of recovery in 2015 to coincide with any other increases, including fuel prices. NSPI's business customers need stability as much as they would benefit from lower rates. SBA believes this is especially true of the small businesses where there is less medium and long term business and financial planning. This would allow the 3% already agreed upon to be implemented.
>
> If there are disallowances in excess of the 2012 FAM AA adjustment SBA urges the Board to consider providing the benefit of the returning funds for disallowances to customer classes as a single month rebate within two months of the Board issuing a decision. This would provide a more pronounced benefit to SBA's small business constituents, an economic stimulus of sorts.
>
> [SBA Closing Argument, November 23, 2012, p. 24]

[435] In its Closing Submissions, the Province "urged the Board to ensure that any savings that result from the FAM Audit be passed along to customers as soon as possible".

[436] The political parties who participated in this proceeding submitted that any disallowance should be returned to ratepayers immediately.

[437] With respect to the fuel-related disallowances totaling $4,503,000 for the Lingan derates and the Bid B natural gas contract, this amount must be applied to the 2013 FAM Balance Adjustment ("2013 BA").

[438] The Board notes that applying this fuel disallowance to the 2013 BA will actually reduce the fuel deferral to be collected from ratepayers starting in 2015. This deferral of the fuel disallowance is consistent with the manner adopted by the Intervenors for the non-fuel reductions they negotiated in the GRA Agreement.

[439] More importantly, applying the fuel disallowance amount against the deferral will benefit ratepayers by reducing the deferral amount attracting interest and the 9% rate of return for NSPI.

[440] A different implementation procedure applies for the $2 million disallowance arising from NSPI's conduct contrary to the POA.

[441] While some Intervenors may have suggested different alternatives were available to the Board, it considers that this disallowance must be applied against NSPI's 2012 earnings.

[442] The Board has decided that the 2012 revenue requirement is to be adjusted for purposes of applying clause 26 of the 2012 Settlement Agreement. Clause 26 reads as follows:

> Subject to necessary adjustments to incorporate paragraph 7 above, the s.21 AAA Mechanism will continue to operate on a go forward basis until the s.21 amount is fully paid. Amounts in excess of both the range of return on equity and in excess of the room available in the s.21 AAA Mechanism will be returned to customers.
>
> [Decision, 2011 NSUARB 184, p. 13]

[443] The threshold for triggering payment under clause 26 of the 2012 Settlement Agreement will be $2 million lower than it otherwise would have been. If NSPI otherwise over earns in 2012, an additional $2 million will be applied to the deferrals for the benefit of ratepayers.

[444] The Board notes that while this $2 million disallowance does not provide a direct benefit to ratepayers going forward, it could, as explained above, benefit ratepayers if there is an impact on the treatment of the s. 21 amount under the 2012 Settlement Agreement.

[445] The Board directs the implementation of all the disallowances as described in this section.

11.12 Perspective

[446] NSPI's fuel budget over the two year period covered by the Audit is approximately $1 Billion or $500 Million per year. The Liberty Audit recommended a disallowance of approximately $10 million in fuel spending, approximately 1% of the budget. Liberty recommended further investigation of the hedging issue. While Liberty made other recommendations in the Audit, it did not question 99% of the fuel spending undertaken by NSPI and indeed, parts of the Audit were very complimentary to NSPI's fuel acquisition activities.

[447] From the outset NSPI chose to focus its own and the public's attention on this 1% - ignoring the balance of the Audit and indeed trashing the whole Audit.

[448] NSPI also chose to focus on reputation; its own reputation alleging defamation, which lead to a separate preliminary hearing in August, and attacking Liberty's reputation, alleging bias, incompetence, and irresponsibility, among other things.

[449] Power rates are, at the best of times, a top of mind issue with the public in Nova Scotia. The majority of the members of the public are NSPI's customers.

[450] NSPI is free, and must be free, to conduct any case before the Board in the manner that best suits it.

[451] However, having read the comments of the CA, SBA and Avon, who are all regular parties to these proceedings, and having reflected on the matter, the Board cannot help but observe that NSPI's relationship with the public and other parties to most of these proceedings has suffered damage.

[452] One of the conditions attached to the approval of the FAM was "a meaningful audit process under the administration of the Board". The Board and customers expect the Board's auditor to ask the tough questions and to identify areas where costs might have been avoided. Simply because the Audit recommends a disallowance, does not mean the Audit is flawed or biased. In making a disallowance the Board is not finding that NSPI's fuel team are not competent or professional. They are both competent and professional.

[453] Credit rating agencies and others who follow these proceedings should understand this perspective. The FAM Audit process approved without question 99% of NSPI's fuel costs. The Audit was critical of only 1%. The Board has, in the result,

accepted two recommendations for disallowance, amounting to much less than 1%. NSPI has a functioning FAM.

12.0 MISCELLANEOUS

12.1 Information Requests

[454] The Board observed a practice NSPI adopted in this hearing which had not been prevalent in the past by answering an IR as follows:

> NS Power will provide this information to the Board upon request.
>
> [Exhibit N-32, IR-33]

[455] Such an answer is not responsive or helpful to the questioner. An IR is either "in scope" and relevant and deserves an answer or is "out of scope" and irrelevant, in which case NSPI can refuse to answer it. NSPI should take a position in the original answer which, if the questioner disagrees, can be further reviewed by the Board at the request of the questioner. The response noted above simply delays proceedings which are often on a very tight time schedule. This is not acceptable.

13.0 COMPLIANCE FILING

[456] The rates approved in this Decision are effective January 1, 2013 and January 1, 2014, respectively.

[457] NSPI is directed to file a Compliance Filing as soon as conveniently possible.

[458] The Formal Intervenors must provide comments, if any, no later than three full business days thereafter.

[459] Further, the Board directs NSPI to outline in 2013 and 2014 where it has applied the $27.5 million non-fuel cost reductions negotiated in the GRA Agreement. This disclosure is to accompany the year-end financial statements in the respective years.

14.0 SUMMARY OF BOARD FINDINGS

Settlement Agreement

[460] This Decision deals with the Board's consideration of both NSPI's general rate application and of the FAM Audit Report.

[461] NSPI's Application requested the Board's approval of a Rate Stabilization Plan ("RSP"). The RSP is a two-year rate plan, with net increases of three percent per year effective on each of January 1, 2013, and January 1, 2014. According to the Application, the increases will cover a portion of the increased costs forecast by NSPI in each of the next two years. NSPI proposed the remaining revenue requirement be deferred for future recovery commencing in 2015.

[462] NSPI reached a settlement agreement ("GRA Agreement") with most of its customer classes, including the CA, the SBA and Avon.

[463] The Board approves the GRA Agreement, which adopts the two year RSP proposed by NSPI and represents a comprehensive resolution of many contested issues between NSPI and the Intervenors, who indicated that, without the RSP, customers would have faced much larger rate increases, particularly in 2013. They stated that the RSP will "smooth out rate increases experienced by customers" and provide a "predictable measure of stability" over the next two years.

[464] The GRA Agreement provides for a $27.5 million non-fuel cost reduction in NSPI's deferral account balance. The deferral of forecasted revenue requirement will not exceed $47.1 million at December 31, 2013 and will not exceed $84.8 million at December 31, 2014.

[465] In the Board's view, an important component of the GRA Agreement which will benefit customers is the RSP, which limits across-the-board 3% increases in each of 2013 and 2014, while deferring recovery of NSPI's remaining revenue requirement to 2015. The recovery of the deferral, commencing in 2015, will coincide with the end of the Section 21 Tax Deferral, which has already been included in existing rates over eight years ending in March 2015. The deferral in the RSP will be collected over an 8 year period beginning in 2015.

[466] The GRA Agreement also reduces NSPI's return on equity from 9.2% to 9.0%, along with a change to the earnings band of 8.75 % to 9.25 %. This will also result in further reductions to NSPI's revenue requirement for 2013 and 2014.

[467] The rates approved in this Decision are effective January 1, 2013 and January 1, 2014, respectively. Rates will increase by 3% for each customer class on January 1, in each of 2013 and 2014.

Pension Costs

[468] In last year's general rate Decision, the Board indicated that it would investigate the issue of pension costs in this proceeding. It appears to the Board that until very recently NSPI has done little, if anything, to address increasing pension costs.

[469] NSPI confirmed to the Board that it reached an agreement with the IBEW on the terms of a new collective agreement which was approved on November 5, 2012, including changes to the pension plan.

[470] The Board sees this change as a significant step in pension reform. The Board accepts these changes as adequate initial steps.

[471] In future years these costs savings will be embedded in the revenue requirement asked of customers. However, the Board expects NSPI in future to take additional steps to improve contributions to, and the funding of, the pension plan.

[472] Two issues also arose in the course of the hearing with respect to NSPI's Supplemental Executive Retirement Plan (SERP). This plan is available to employees who earn more than approximately $150,000 per year. The Board considers it unreasonable that the most highly paid employees working for NSPI make no contribution to the supplemental pension plan.

[473] NSPI is free to continue to provide that benefit, however, the Board directs that in the test years and in future NSPI must adjust the revenue requirement to deduct an amount from the SERP pension payments to reflect a deemed employee contribution to the SERP, on the assumption that the employee had contributed 50% to the pension plan and the employer 50%. The Board understands the amount to be disallowed is $2.05 million in 2013 and $2.2 million in 2014.

[474] Also, NSPI secures the SERP pension by purchasing a letter of credit, using funds paid entirely by ratepayers. In the Board's view, payment for that portion of the letter of credit that secures the pension is an unnecessary expense and is not an expense that should be borne by ratepayers. Accordingly, the Board disallows that amount from the revenue requirement.

[475] These deductions are in addition to the $27.5 million provided for in the GRA Agreement.

Executive Compensation

[476] The Legislature has passed amendments to the *Public Utilities Act* limiting the amount of remuneration, bonuses and other benefits that can be recovered from rates with respect to compensation of executive employees of NSPI.

[477] In its Compliance Filing, NSPI is to reduce its revenue requirement to reflect the changes as a consequence of this legislation, including pension payments on behalf of executives.

LED Streetlighting

[478] The Board agrees that dealing with the streetlight issue as a part of a capital work order is a reasonable approach with the exception of the net book value question.

[479] The Board denies HRM's request to recalculate the net book value of streetlights currently included in the NSPI rate base. How this amount is shared between municipalities is something NSPI should work out with them.

[480] In a second issue raised by HRM, the Board orders NSPI to confirm by February 28, 2013 that no new non-LED streetlights were ordered or purchased after the Board's 2012 GRA Decision.

Low Income Residential Customers

[481] The Board approves the Settlement Agreement filed by the Affordable Energy Coalition, NSPI and the CA, which sets up a consultative process "with a view to resolving bill payment, credit and collection matters affecting low income residential customers".

Cost of Service – Biomass

[482] The Board finds that NSPI's recently constructed 60 MW biomass plant at Point Tupper, Nova Scotia, has similar characteristics to any other steam plant. The Board directs that it should be classified on the basis of system load factor, because it makes a contribution to capacity and provides firm power.

Natural Gas Storage

[483] The Board denies the request of Alton Natural Gas Storage L.P. to order NSPI's participation in a natural gas study with Alton and Heritage Gas.

FAM Audit

[484] The Liberty Consulting Group was engaged by the Board to conduct the FAM Audit for the period covering 2010 and 2011. The FAM Plan of Administration ("POA") provides that an audit of the FAM will be done every second year.

[485] The Board made a number of findings in relation to the FAM Audit Report. The Board noted the importance of transparency, as well as the full and timely disclosure of complete and adequate information, in its original approval of the FAM.

[486] Credit rating agencies and others who follow these proceedings, including the public, should understand that the FAM Audit process approved without question 99% of NSPI's fuel costs. The Audit was critical of only 1%. The Board has, in the result, accepted two recommendations for disallowance, amounting to much less than 1%. In making a few disallowances, the Board is not finding that NSPI's fuel team are not competent or professional. They are both competent and professional. NSPI has a functioning FAM.

Lingan Derates

[487] The Board finds, on the balance of probabilities, that NSPI was aware in July/August 2010 that there were quality issues related to the Prince coal. NSPI did not investigate and test other coal blends to mitigate the risks of the failure to meet opacity limits.

[488] In failing to mitigate the known risks of derates from using Prince coal, the Board finds that NSPI was imprudent. The Board also concludes that imprudence on the part of NSPI led to the derate of the Lingan facility.

[489] The Board orders a $3.6 million disallowance with respect to the Lingan derates.

Natural Gas Contracts

[490] With NSPI's long term natural gas supply contract with Shell coming to an end on October 31, 2010, NSPI issued a Request for Proposals to acquire replacement quantities of natural gas to supply its projected needs. One of the two lowest offers ("Bid A") was withdrawn after NSPI felt it had already accepted the offer via a term sheet. The other lowest offer ("Bid B") was rejected by NSPI, largely due to NSPI's concern about associated transportation costs and potential risk of supply interruption.

[491] The Board does not believe that NSPI's actions with respect to Bid A were imprudent. Based on the evidence, it appears to the Board there was never a meeting of the minds between NSPI and Bidder A on the terms of the offer. Liberty acknowledged that there was not an enforceable contract.

[492] However, with respect to Bid B, the Board is very concerned about NSPI's failure to properly analyze the costs and benefits of taking an assignment of this very favourably priced contract.

[493] Liberty prepared an analysis that showed that NSPI was better off after five years, based on this favourable pricing, as compared to other pricing it was able to obtain even if the transportation contract was useless from that point forward.

[494] In the Board's view, NSPI was imprudent in failing to properly analyze the risks and benefits associated with the Bid B contract which the Board believes could have been very beneficial for ratepayers.

[495] The Board disallows $903,000 related to the failure to take an assignment of the Bid B contract for the period from November 1, 2010 to December 31, 2011 (i.e.,

426 days). As this was a longer term contract the impact of this finding on any future test years will be the subject of consideration in future audits.

[496] Finally, the Board does not believe there is a sufficient basis for it to make any disallowance based on NSPI's monthly, seasonal or daily purchases.

Natural Gas Markets

[497] On the last day of hearing, and in a confidential session, NSPI disclosed new and important evidence concerning its activities in the natural gas market. Unfortunately, because of its confidential nature, the Board can disclose little, if any, of this evidence in this public Decision. This evidence was not previously disclosed to Liberty, the Intervenors or the Board.

[498] NSPI's actions in withholding this information are both inexplicable and inexcusable. In the Board's view, that conduct cannot go unsanctioned. The Board will impose a financial disallowance to NSPI, as described below.

[499] However, on the substantive issue related to natural gas markets, the Board makes no other disallowance with respect to NSPI's gas market activity.

Natural Gas Hedging

[500] The Board is satisfied that NSPI could not reasonably have foreseen the events commencing in December 2010, which would lead to a significant change in the "basis differential" and result in the "basis blowout". Accordingly, the Board finds that no imprudence disallowance should be imposed on NSPI with respect to this issue.

FAM Audit Process

[501] The Board concludes that Liberty's FAM Audit followed appropriate auditing standards. The FAM Audit was also conducted in a manner consistent with the process contemplated under the POA approved by the Board. In addition, the Board noted that Liberty's work on this file was supported by the Intervenors representing most customer classes.

[502] The Board makes no directive at this time with respect to possible changes to the POA or future FAM Audits. The Board indicated during the hearing that it would be more appropriate to review all aspects of the FAM in a separate proceeding where the FAM and all other issues related to it (including the POA) can be examined, rather than in a piecemeal fashion.

[503] The Intervenors and the Board were disappointed with NSPI's response to the FAM Audit. In failing to respond to the draft Audit Report, NSPI acted contrary to the process contemplated in the FAM POA. Its conduct was also contrary to the reasonable expectations of the Board and the Intervenors. NSPI also acted in a manner which is not consistent with the spirit and intent of audits generally, including fuel management or prudence audits.

[504] Further, NSPI's course of action distracted and misdirected all parties in this proceeding from addressing some of the other important issues in the hearing. NSPI's course of action had the effect of wasting scarce resources, in terms of time, money and human resources, for all parties.

[505] In the future, the Board expects NSPI to conduct itself in accordance with the intent and the terms of the POA, including providing a meaningful response to the

draft Audit Report, along with an indication of which audit findings or recommendations it agrees with and which it does not.

[506] The Board notes that Liberty bears some of the responsibility for the acrimonious relationship which developed over the course of the FAM Audit process between NSPI and its FAM auditor. Some of Liberty's language was provocative in a way it did not have to be. In retrospect, the Utility's response might have been more tactful and reserved if Liberty had adopted a more measured tone in its criticism of NSPI's FAM activities. This would have resulted in a more productive Audit process.

Remaining Recommendations in the FAM Audit

[507] The Board directs that NSPI proceed with the implementation of the remaining recommendations it has agreed with in Undertaking U-22. In the instances where NSPI has not provided an action plan for the recommendations with which it agrees, it is directed to file its implementation plans by February 28, 2013.

[508] In the case of recommendations which are not agreed to by NSPI, it is to file a detailed explanation why it does not agree. This is also to be filed by February 28, 2013.

[509] The Intervenors will then be permitted to provide their comments to the Board by March 29, 2013, with respect to any of the remaining recommendations.

Disallowed Costs Related to FAM Audit

[510] The Board expects NSPI to comply with its Decisions, Orders and directives, including its oversight procedures like the FAM Audit and the POA. In the Board's opinion, NSPI's conduct in relation to the NEB issue and its decision not to

comment on the draft Audit report were both unreasonable and inappropriate. Its conduct on these specific points resulted in unnecessarily extending the length of the hearing and wasting the time, money and effort of the Intervenors and Board Counsel.

[511] In these circumstances, the Board finds that a sanction is warranted as against NSPI and concludes that a disallowance of $2 million is appropriate.

Implementation of the FAM Disallowance

[512] With respect to the fuel-related disallowances totaling $4,503,000 for the Lingan derates and the Bid B natural gas contract, this amount must be applied to the 2013 FAM Balance Adjustment ("2013 BA").

[513] The Board notes that applying this fuel disallowance to the 2013 BA will actually reduce the fuel deferral to be collected from ratepayers starting in 2015. This deferral of the fuel disallowance is consistent with the manner adopted by the Intervenors for the non-fuel reductions they negotiated in the GRA Agreement.

[514] More importantly, applying the fuel disallowance amount against the deferral will benefit ratepayers by reducing the deferral amount attracting interest and the 9% rate of return for NSPI.

[515] A different implementation procedure applies for the $2 million disallowance arising from NSPI's conduct contrary to the POA. This disallowance must be applied against NSPI's 2012 earnings.

[516] The threshold for triggering payment under clause 26 of the 2012 Settlement Agreement will be $2 million lower than it otherwise would have been. If NSPI otherwise over earns in 2012, an additional $2 million will be applied to the deferrals for the benefit of ratepayers.

Other Revenue Requirement Reductions

[517] As noted earlier in this summary, the reductions in pension costs and executive salaries will lower the test year revenue requirements, in addition to the $27.5 million provided for in the GRA Agreement.

[518] An Order will issue following the Compliance Filing.

DATED at Halifax, Nova Scotia, this 21st day of December, 2012.

Peter W. Gurnham

Roland A. Deveau

Kulvinder S. Dhillon

APPENDIX A

NOVA SCOTIA POWER INC.
2013 RATE APPLICATION – INCLUDING THE FAM AUDIT P-893/M04972

LIST OF PARTICIPANTS

Affordable Energy Coalition

Alton Natural Gas Storage LP

Avon Group
(Avon Valley Greenhouses Ltd.)
(Canadian Salt Company Limited)
(CFK Inc.)
(Crown Fibre Tube Inc.)
(Halifax Grain Elevator Limited)
(Imperial Oil Limited)
(Lafarge Canada Inc.)
(Maritime Paper Products Ltd.)
(Michelin North America (Canada) Inc.)
(Minas Basin Pulp & Power Company Ltd.)
(Oxford Frozen Foods Limited)
(Sifto Canada Corp.)
(Nustar Terminals Canada Partnership)

Bowater Mersey Paper Company Limited

Cape Breton Explorations Ltd.

Consumer Advocate

Halifax Regional Municipality

Municipal Electric Utilities of Nova Scotia Co-operative

Municipality of the District of Yarmouth

Nova Scotia Department of Energy and Nova Scotia Environment

Nova Scotia Liberal Caucus

Nova Scotia Power Inc.

Progressive Conservative Caucus Office

Small Business Advocate

Strait Area Mayors & Wardens and Town of Port Hawkesbury

Union of Nova Scotia Municipalities

IMPACT OF CHANGE IN CAPITAL STRUCTURE ON COST OF EQUITY:

Formula for After-Tax Weighted Average Cost of Capital:

$WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)

APPROACH 1:

The after-tax weighted average cost of capital ($WACC_{AT}$) is invariant to changes in the capital structure. The cost of equity increases as leverage (debt ratio) increases,

$WACC_{AT(LL)}$ = $WACC_{AT(ML)}$

Where LL = less levered (lower debt ratio)
ML = more levered (higher debt ratio)

ASSUMPTIONS:

Debt Cost	=	Market Cost of Long Term Debt for A rated utility
	=	4.20%
Equity Cost	=	9.10%
Tax Rate	=	31.0%
CEQ Ratio	Step (1)	37.5%
Debt Ratio	Step (1)	62.5%
CEQ Ratio	Step (2)	30.0%
Debt Ratio	Step (2)	70.0%

STEPS:

1. Estimate $WACC_{AT}$ for the less levered sa (common equity ratio of 37.5%)

   $WACC_{AT}$ = (4.20%)(1-.310)(62.5%) + (9.10%)(37.5%)
   = 5.22%

2. Estimate Cost of Equity for sample at 30.0% common equity ratic $WACC_{AT}$ unchanged at 5.22%

   $WACC_{AT}$ = (Debt Cost)(1-tax rate)(Debt Ratio) + (Equity Cost)(Equity Ratio)
   5.22% = (4.20%)(1-.310)(70.0%) + (X)(30.0%)
   Cost of Equity at 30.0% Equity Ratio = 10.65%

3. Difference between Equity Return at 37.5% and 30.0% common equity ratios:

   10.65% - 9.10% = 1.55% (155 basis points)

APPROACH 2:

After-Tax Cost of Capital Falls as Debt Ratio Increases; Cost of Equity Increases

$$WACC_{AT(LL)} = WACC_{AT(ML)} \times \frac{(1-tD_{LL})}{(1-tD_{ML})}$$

Where LL,ML as before
t = tax rate
D = debt ratio

ASSUMPTIONS:

Debt Cost	=	Market Cost of Long Term Debt for A rated utility
	=	4.20%
Equity Cost	=	9.10%
Tax Rate	=	31.0%
CEQ Ratio	Step (1)	37.5%
Debt Ratio	Step (1)	62.5%
CEQ Ratio	Step (2)	30.0%
Debt Ratio	Step (2)	70.0%

STEPS:

1. Estimate $WACC_{AT}$ for less levered sample (common equity ratio of 37.5%)

$WACC_{AT}$ = (4.20%)(1-.310)(62.5%) + (9.10%)(37.5%)
= 5.22%

2. Estimate $WACC_{AT}$ for more levered firm (common equity ratio of 30.0%)

$WACC_{AT(ML)} = WACC_{AT(LL)} \times (1\text{-t} \times \text{Debt Ratio}_{ML})/(1\text{-t} \times \text{Debt Ratio}_{LL})$

$$WACC_{AT(ML)} = 5.22\% \times \frac{(1-.310 \times 70.0\%)}{(1-.310 \times 62.5\%)}$$

$WACC_{AT(ML)}$ = 5.07%

3. Estimate Cost of Equity at new $WACC_{AT}$ for more levered firm:

$WACC_{AT(ML)}$ = (Debt Cost)(1-tax rate)(Debt Ratio_{ML}) + (Equity Cost)(Equity Ratio_{ML})

5.07% = (4.20%)(1-.310)(70.0%) + (X)(30.0%)

Cost of Equity at 30.0% Equity Ratio = 10.15%

4. Difference between Equity Return at 37.5% and 30.0% common equity ratios:

10.15% - 9.10% = 1.05% (105 basis points)

Ontario Energy Board

EB-2009-0084

Report of the Board

on the Cost of Capital for Ontario's Regulated Utilities

December 11, 2009

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Executive Summary

Earlier this year, the Board initiated a consultative process to assist the Board in reviewing its cost of capital policies. The consultative process began in February 2009 and has culminated in this policy report of the Board. All materials in relation to this consultation are available on the Board's web site.

The Board affirms its view that the Fair Return Standard frames the discretion of a regulator, by setting out three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. Notwithstanding this obligation, the Board notes that the Fair Return Standard is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital. The Board also confirms other key principles with respect to its cost of capital policy.

The Board has analyzed submissions, discussions at the consultation and the final written comments of participants to the consultation with these general principles in mind. In light of the information and supporting empirical analysis provided in consultation with stakeholders, the following refinements to the Board's policies with regard to the cost of capital are set out in this report.

1. <u>Need to Reset and Refine Existing Return on Equity Formula:</u> The Board will continue to use a formula-based equity risk premium approach. Also, the Board is of the view that the Long Canada Bond Forecast (the "LCBF") continues to be an appropriate base upon which to begin the return on equity calculation. However, in order to ensure that on an ongoing basis changing economic and financial conditions are adequately and appropriately accommodated in the Board's formulaic approach for determining a utility's equity cost of capital, the Board has determined that its current formula-based return on equity approach needs to be reset and refined.

- Reset the Formula: The formula needs to be reset to address the difference between the allowed return on equity arising from the application of the formula and the return on equity for a low-risk proxy group that cannot be reconciled based on differences in risk alone. Based on the equity risk premium recommendations derived from multiple approaches that were provided by all participants in this consultation, the Board has determined that an initial equity risk premium of 550 basis points is appropriate for the purposes of deriving the initial return on equity to be embedded in the Board's reset and refined return on equity formula. This includes an implicit 50 basis points for transactional costs. Consequently, assuming a forecast long term government of Canada bond yield of 4.25%, the initial return on equity to be embedded in the Board's reset and refined return on equity formula will be 9.75% (i.e., 4.25% + 550 basis points = 9.75%).

- Refine the Formula: The formula also needs to be refined to reduce its sensitivity to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity. First, the Board views the determination of the LCBF adjustment factor to be an empirical exercise, and as such, based on the empirical analysis provided by participants in conjunction with the consultation, the Board is of the view that the LCBF adjustment factor should be set at 0.5. Second, based on the analysis provided by participants to the consultation, the Board concludes that there is a statistically significant relationship between corporate bond yields and the cost of equity, and that a corporate bond yield variable should be incorporated in the return on equity formula. The Board has determined that it will use a utility bond spread based on the difference between the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond index yield and the long Canada bond yield and that the utility bond spread reflected will be subject to a 0.50 adjustment factor, consistent with the empirical analyses provided by participants to the consultation.

2. Refine Long-term Debt Guidelines and Approach to Determine Rate: The determination of the cost of long-term debt was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely

supported the continuation of the Board's existing policies and practices. However, in the report the Board formalizes certain approaches to reflect recent determinations regarding long-term debt costs. Further, the deemed long-term debt rate will be estimated including the A-rated utility bond index yield consistent with refinement to the return on equity formula.

3. Refine Approach to Determine Deemed Short-term Debt Rate: The determination of the cost of short-term debt also was not a primary focus of the consultation. However, to better reflect utility short-term debt costs, the Board has determined that the spread over the Bankers' Acceptance rate used to derive the deemed short-term debt rate should be based on real market quotes for issuing spreads over Bankers' Acceptance rates for the cost of short-term debt.

The Board will apply the methods set out in this report annually to derive the values for the return on equity and the deemed long-term and short-term debt rates for use in cost of service applications. If the application of these methods produces numerical results that, in the view of the Board, raise doubt that the Fair Return Standard is met, the Board may then use its discretion to begin a consultative process. Also, the Board has determined that a review period of five years provides an appropriate balance between the need to ensure that the formula-generated return on equity continues to meet the Fair Return Standard and the objective of maintaining regulatory efficiency and transparency. Accordingly, the Board intends to conduct its first regular review in 2014.

The remainder of this Report sets out in greater detail the Board's policy as summarized above, as well as the considerations underlying the different elements of the Board's approach.

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1 Introduction

The Ontario Energy Board (the "Board") adopted a formula-based approach using the Equity Risk Premium ("ERP") method for determining the fair rate of return on common equity for Ontario natural gas utilities in March, 1997. Application of the approach was extended to the electric utilities when the Board's regulatory oversight expanded to include the electricity sector in 1999. The Board's current approach for determining the cost of capital is set out in the *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*, dated December 20, 2006 (the "December 20, 2006 Report").

Earlier this year, the Board initiated a consultative process to assist the Board in reviewing its cost of capital policies. The consultative process, detailed below, began in February 2009 and has culminated in this policy report of the Board. All materials in relation to this consultation are available on the Board's web site.

This report sets out the Board's updated approach to cost of capital and the methods that the Board will use to annually update the cost of capital parameters for all rate-regulated utilities. Specifically, this report refines the Board's policies regarding the cost of capital in the following five ways: (i) resetting and refining the return on equity ("ROE") formula; (ii) refining long-term debt guidelines and the approach to determining the deemed long-term debt rate; (iii) refining the approach to determining the deemed short-term debt rate; and (iv) setting out an annual review process to be used by the Board in conjunction with each application of the methodology to ensure that the results meet the Fair Return Standard ("FRS"); and (v) developing a framework within which to conduct a periodic review of the Board's cost of capital policies.

Organization of this Report

This report is organized as follows: The consultative process is detailed in Chapter 2. Important principles in the regulation of cost of capital are discussed in Chapter 3. The Board's policy for and analysis of cost of capital are outlined in Chapter 4. Certain implementation considerations are identified in Chapter 5, and the annual update process and provision for periodic review of the cost of capital policies are addressed in Chapter 6. A summary of the formula-based ROE guidelines in effect in the 2009 rate year is provided in Appendix A. The new methods that the Board will use to annually update the cost of capital parameters as set out in this report are contained in the Appendices.

2 Consultative Process

On February 24, 2009, the Board issued a letter which set out its determination on the values for the ROE and the deemed long-term and short-term debt rates for use in the 2009 rate year cost of service applications. These cost of capital parameter values were calculated based on the methodologies and formulae set out in the December 20, 2006 Report. In that letter, the Board advised participants that it would be initiating a review of its current policy regarding the cost of capital.

2.1 Overview

Initial Consultation

On March 16, 2009, the Board initiated a consultation process to help it to determine whether current economic and financial market conditions warrant an adjustment to any of the cost of capital parameter values (i.e., the ROE, long-term debt rate, and/or short-term debt rate) set out in the Board's February 24, 2009 letter. The consultation was initiated, in part, by (i) the fact that the difference between the cost of equity and the cost of long-term debt values determined by the Board for the 2009 Cost of Service Applications was only 39 basis points (8.01% and 7.62%), versus a difference of 247 basis points in 2008; and (ii) concern that the Board did not have a sufficiently robust approach within which to exercise its discretion to adjust any or all of the values produced by the application of the methodology. The Board indicated that the objective of the consultation was to test whether the values produced, and the relationships among them, are reasonable in the current economic and financial market conditions, and to allow the Board to determine if, when and how to make any appropriate adjustments to any of the values.

Cost of Capital Review

In light of stakeholders' comments, the Board determined not to vary the 2009 parameter values for 2009 rates. In its June 18, 2009 letter setting out this determination, the Board explained that it was not persuaded that there was a sufficient basis to do so, in a timely manner. Nevertheless, the Board determined that further examination of its policy regarding the cost of capital was warranted to ensure that, on a going forward basis, changing economic and financial conditions are accommodated if required. Therefore, the Board advised that it would proceed with a review of its policy regarding the cost of capital. The Board indicated that any changes to the policy made as a result of this review would apply to the setting of rates for the 2010 rate year.

The Board set an issues list to form the basis of its review which took into account the stakeholder comments received in response to the Board's March 16, 2009 letter and other information that the Board considered relevant (the "Issues List"). This Issues List was posted to the Board's web site on July 30, 2009. Appended to the Issues List were: a summary of stakeholder options in response to the Board's March 16, 2009 letter; and a list of references to documents germane to the consultation.

The Issues List

In the cover letter to the Issues List, the Board affirmed its view that the FRS constitutes the over-arching principle for setting the cost of capital, which is one input into the setting of rates. The Board also set the scope for the consultation as follows. First, that the consultation would deal only with the means by which the Board determines the cost of capital. The actual effect, if any, on specific utilities' revenue requirements as a result of any updated policies arising from this consultation and the determination of just and reasonable rates would not be addressed in this process, but in future rate proceedings. Second, that historically, the Board has found the ERP approach to be pragmatic and efficient given the Ontario market structure and the number of utilities that the Board regulates. The Board concluded that an ERP approach remains the most appropriate in the current circumstances. However, the Board decided to review the application and the derivation of the current ERP approach to determine if it is sufficiently robust to guide the

Board's discretion in applying the FRS. And third, the Board stated that the application of the FRS would be central to the consultation.

The Board identified three areas where further information was needed:

- Potential adjustment to the established cost of capital methodology (i.e., based on the ERP approach) to adapt to changes in financial market and economic conditions;
- Determination of reasonableness of the results based on a formulaic approach for setting cost of capital parameter values; and
- Board discretion to adjust those results, if appropriate.

The Board received written comments from stakeholders identifying their views and positions on the listed issues and held a Stakeholder Conference to provide a forum for discussion of the substantive matters contained in the Board's Issues List.

The Stakeholder Conference

The Stakeholder Conference was held over a three day period, September 21, 22 and October 6, 2009.

The Board identified the objectives of the stakeholder conference as follows:

- To allow participants and their respective experts to clarify and elaborate on their written comments;
- To provide participants with an opportunity to explore in some depth the rationale and merits of alternatives supported by other participants and their respective experts; and
- To help the Board gain, through the presentations and an interactive exchange with participants and their respective experts, a clearer understanding of the positions of participants and of significant issues and areas of concern.

At the start of the Stakeholder Conference, a Capital Markets Panel provided participants with a comprehensive overview of capital markets conditions. The Panel was comprised of practicing capital markets individuals, representing investor, equity analyst, and bond market perspectives. Representatives from Sun Life Financial, TD Securities Inc., Scotia Capital, and Macquarie Capital Markets participated on the Capital Markets Panel. Panel members addressed matters such as:

- What the capital markets have been through, where they are today, and set out key indicators or variables that are of interest prospectively;
- Overall availability of capital and the cost of that capital (both debt and equity);
- Access to bank credit/debt/equity, the absolute cost of debt, spread, term availability, and covenants;
- Spreads that have been and are being observed and under what conditions; and
- Activity that has been and/or is evident in the market in terms of funds flow into the market and between asset classes.

Following the Capital Markets Panel discussion, the following individuals provided presentations to participants and the Board at the Stakeholder Conference:

- Dr Laurence D. Booth, Professor, University of Toronto (consultant for the Building Owners and Managers Association of the Greater Toronto Area, the Consumers Council of Canada, Canadian Manufacturers and Exporters, Industrial Gas Users Association, London Property Management Association, and the Vulnerable Energy Consumer's Coalition);
- Mr. Donald A. Carmichael, Independent Consultant (consultant for Enbridge, Fortis Ontario Inc., and Toronto Hydro-Electric System Limited);
- Mr. James M. Coyne, Senior Vice President, Concentric Energy Advisors (consultant for Enbridge, Hydro One Networks, Inc. and the Coalition of Large Distributors [Enersource Hydro Missisauga Inc., Horizon Utilities Corporation, Hydro Ottawa Limited, PowerStream Inc., Toronto Hydro-Electric System Limited and Veridian Connections Inc.]);

- Mr. John Dalton, Power Advisory LLC (consultant for Great Lakes Power Transmission);
- Ms Kathleen McShane, President, Foster Associates (consultant for Electricity Distributors Association);
- Dr Lawrence P. Schwartz, Consulting Economist (consultant for Energy Probe Research Foundation); and
- Dr. James Vander Weide, Research Professor of Finance and Economics, Duke University, The Fuqua School of Business (consultant for Union Gas).

Subsequent to the Stakeholder Conference and in light of the presentations made by participants and discussions at the conference, the Board received final written comments from participants. The Board indicated in its October 5, 2009 letter to participants that following the receipt of final written comments, it would review all of the materials, including Stakeholder Conference transcripts and all of the written comments in making its determination, and that the Board aimed to issue its report in December.

2.2 Approach to Developing Regulatory Policy

In their final comments to the Board, several participants expressed concern regarding the potential scope of outcomes arising from this consultation. In a joint submission, the Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition and the Canadian Manufacturers and Exporters describe their understanding that the consultation was intended to have a limited scope, and pointed to several statements made by the Board regarding the scope of the consultation. In summary, the submission states: "[i]n these circumstances, we suggest that the possible outcomes of this consultation are limited to a Board report which evaluates whether any of the information presented during the course of the consultative is sufficient to call into question the continued appropriateness of any element of the Board's current cost of capital methodology."[1] The School Energy Coalition filed a similar submission, stating: "[t]he primary purpose of this part of the consultation, as

[1] Final Comments on behalf of the Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition and the Canadian Manufacturers and Exporters. October 30, 2009. p. 3.

noted by the Board in a number of communications, and reiterated at the stakeholder conference, is to help understand whether the current approach to cost of capital has sufficient robustness to be relied on by the Board in all circumstances."[2]

Although the Board appreciates the perspectives of these participants about their expectations, it does not agree that the scope of the consultation was limited in the fashion that they suggest. The Issues List set out a comprehensive set of issues that set the scope for this consultation. Amongst the issues are the following: How should the Board establish the initial ROE for the purpose of resetting the methodology? Does the current approach used by the Board to calculate the ERP remain appropriate? If not, how should the ERP be calculated?[3]

In response to a letter it received on August 13, 2009 from Mr. Robert Warren, sent on behalf of the Consumers Council of Canada, the Vulnerable Energy Consumers Coalition and the London Property Management Association, the Board again invited participants to provide any information they felt appropriate in responding to the questions on the Issues List:

> Stakeholders are asked to provide in their written comments answers to the questions identified in the Board's Issues List. To help the Board in its review, the Board invites stakeholders to include in their written comments some analytical support and detailed information to identify their views and support their positions in response to the Board's questions.[4]

It is the Board's view, therefore, that the policies determined by the Board in this report are within the scope of the consultation. The Board has benefitted from the materials and submissions received from the participants. This information contributes to the substantive foundation upon which the Board will base its policies. The Board does not believe that the

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[2] Final Comments on behalf of the School Energy Coalition, p. 2.
[3] Ontario Energy Board. Letter to Participants re: Consultation on Cost of Capital – Issues List, Attachment B: Issues for Discussion at Stakeholder Conference. July 30, 2009. Questions 10 and 13.
[4] Ontario Energy Board. Letter to Mr. Robert B. Warren re: Consultation on Cost of Capital (Board File No.: EB-2009-0084). August 20, 2009.

extensive body of information before it would be materially improved by a hearing process, as was suggested by some participants.

Courts have long recognized that duties of procedural fairness such as the requirement of a hearing apply to adjudicative decisions and decisions affecting specific rights, interests and privileges. Where a board is engaged, as here, in the development of a policy guideline, courts have held that it falls to the board to decide on the method of consultation to be employed - as long as the legislative requirements, if any, are met. There also is abundant precedent for this approach within the Board's practice, and it is neither unusual nor improper to develop a guideline through a consultative process.[5]

The final "product" of this process, of course, is a Board policy. This was not a hearing process, and it does not - indeed cannot - set rates. The Board's refreshed cost of capital policies will be considered through rate hearings for the individual utilities, at which it is possible that specific evidence may be proffered and tested before the Board. Board panels assigned to these cases will look to the report for guidance in how the cost of capital should be determined. Board panels considering individual rate applications, however, are not bound by the Board's policy, and where justified by specific circumstances, may choose not to apply the policy (or a part of the policy).

[5] The Board's current methodology for setting electricity rates through the incentive regulation mechanism, for example, was established through a consultative/guideline process.

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3 Context, Background and the Role of the Board

In competitive markets, the outputs of the goods and services of the economy and the prices for these outputs are determined in the market place, in accordance with consumers' preferences and incomes, as well as producers' minimization of cost for a given output. In such a market, the outcome is the efficient allocation of resources, including capital, and social welfare is maximized.

However, in some situations, markets fail to achieve such efficient outcomes. Market failure refers to situations in which the conditions required to achieve the market-efficient outcome are not present. Common examples of market failure are the existence of significant externalities, the exercise of market power by a small number of producers or buyers, natural monopolies, and information asymmetry between producers and their customers.

Electric transmission and distribution companies and natural gas distribution utilities are natural monopolies and are subject to rate regulation in Ontario by the Ontario Energy Board. In this context, the purpose of rate regulation, among other things, is to create or emulate an efficient market solution that cannot otherwise be achieved due to the presence of one or more market failures. As it relates to a rate regulated entity's cost of capital, the role of the regulator is to determine, as accurately as possible, the opportunity cost of capital to ensure that an efficient amount of investment occurs in the public interest for the purpose of setting utility rates.

3.1 Fair Return Standard

On July 30, 2009 the Board issued a letter and its Issues List for the then planned stakeholder consultation. In that letter, the Board communicated its view that the FRS constitutes the over-arching principle for setting the cost of capital, which is one input into the setting of rates. There are a number of key messages in this statement.

First, as set out by the Federal Court of Appeal, the cost of capital to a utility "is equivalent to the aggregate return on investment investors require in order to keep their capital invested in the utility and to invest new capital in the utility."[6]

Second, the Federal Court of Appeal also stated:

> … even though cost of capital may be more difficult to estimate than some other costs, it is a real cost that the utility must be able to recover through its revenues. If the… [Board] does not permit the utility to recover its cost of capital, the utility will be unable to raise new capital or engage in refinancing as it will be unable to offer investors the same rate of return as other investments of similar risk. As well, existing shareholders will insist that retained earnings not be reinvested in the utility.[7]

Thirdly, the Board is of the view that the process to determine the cost of capital aligns the private interest of the utility and its shareholders with the public interest, and notes that the Federal Court of Appeal said:

> … in the long run, unless a regulated enterprise is allowed to earn its cost of capital, both debt and equity, it will be unable to expand its operations or even maintain its existing ones…This will harm not only its shareholders, but also the customers it will no longer be able to service. The impact on customers and ultimately consumers will be even more significant where there is insufficient competition in the market to provide adequate alternative service.[8]

The determination of a utility's cost of capital must meet the FRS. The FRS is a legal concept, and has been articulated in three seminal court determinations as set out below:

1. In *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia* et. al. 262 U.S. 679 (1923), the FRS is expressed to include concepts of comparability, financial soundness and adequacy:

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[6] TransCanada PipeLines Limited v. National Energy Board et al. [2004] F.C.A 149. Para. 6.
[7] Ibid. Para. 12.
[8] Ibid. Para. 13.

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.

2. In *Northwestern Utilities Limited v. City of Edmonton*, [1929] S.C.R. 186, the FRS concept was described as follows:

> By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise, which will be net to the company, as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.

3. In *Federal Power Commission v. Hope Natural Gas* 320 U.S. 591 (1944), the Court expresses that "balance" is achieved in the ratemaking process, and outlines three elements of a fair return:

> The rate-making process under the act, i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests…the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock…By that standard, the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

The FRS was further articulated by the National Energy Board in its RH-2-2004 Phase II Decision as:

> A fair or reasonable return on capital should:
>
> - be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
> - enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
> - permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).[9]

In its letter of July 30, 2009, the Board noted that the National Energy Board's articulation of the FRS is consistent with the principled approach described on page 2 of the Compendium to the Board's March 1997 *Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities* (the "1997 Draft Guidelines") and the policies set out in the Board's December 20, 2006 Report.

The Board is of the view that the FRS frames the discretion of a regulator, by setting out three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. As set out by Enbridge in their final comments, the Supreme Court of Canada has "described this requirement that approved rates must produce a fair return as an 'absolute' obligation."[10] Notwithstanding this mandatory obligation, the Board notes that the FRS is sufficiently broad that the regulator that applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.

Informed by the comments made by stakeholders in the context of this consultation and the relevant jurisprudence, the Board offers the following observations about the application of the FRS.

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[9] National Energy Board. RH-2-2004, Phase II Reasons for Decision, TransCanada PipeLines Limited Cost of Capital. April 2005. p. 17
[10] *British Columbia Electric Railway Co. Ltd. v. Public Utilities Commission of British Columbia et al [1960] S.C.R. 837*, at p. 848.

First, the Board notes that the FRS expressly refers to an opportunity cost of capital concept, one that is prospective rather than retrospective.

Second, the Board agrees with the National Energy Board which stated that "[i]t does not mean that in determining the cost of capital that investor and consumer interests are balanced."[11] Further, the Board notes that the Federal Court of Appeal was clear that the overall ROE must be determined solely on the basis of a company's cost of equity capital and that "the impact of any resulting toll increase is an irrelevant consideration in that determination. This does not mean however, that any resulting increase in tolls cannot be considered by a tribunal in determining the way in which a utility should recover its costs."[12] The Federal Court of Appeal also stated that:

> It may be that an increase is so significant that it would lead to "rate shock" if implemented all at once and therefore should be phased in over time. It is quite proper for the Board to take such considerations into account, provided that there is, over a reasonable period of time, no economic loss to the utility in the process. In other words, the phased in tolls would have to compensate the utility for deterring the recovery of its cost of capital.[13]

Third, all three standards or requirements (comparable investment, financial integrity and capital attraction) must be met and none ranks in priority to the others. The Board agrees with the comments made to the effect that the cost of capital must satisfy all three requirements which can be measured through specific tests and that focusing on meeting the financial integrity and capital attraction tests without giving adequate consideration to comparability test is not sufficient to meet the FRS.

Fourth, a cost of capital determination made by a regulator that meets the FRS does not result in economic rent being earned by a utility; that is, it does not represent a reward or payment in excess of the opportunity cost required to attract capital for the purpose of

[11] National Energy Board. Reasons for Decision. Trans Quebec & Maritimes Pipelines Inc. RH-1-2008. March 19, 2009. p. 6.
[12] *TransCanada PipeLines Ltd. v. National Energy Board, 2004 FCA 149*, para. 35-36.
[13] *TransCanada PipeLines Ltd. v. National Energy Board, 2004 FCA 149*, para. 43.

investing in utility works for the public interest. Further, the Board reiterates that an allowed ROE is a cost and is not the same concept as a profit, which is an accounting term for what is left from earnings after all expenses have been provided for. The Board notes that while cost of capital and profit are often used interchangeably from a managerial or operational perspective, the concepts are not interchangeable from a regulatory perspective.

Fifth, there was considerable discussion in the consultation about utility bond ratings. The ability of a utility to issue debt capital and maintain a credit rating were generally put forth by stakeholders in the consultation as a sufficient basis upon which to demonstrate that a particular equity cost of capital and deemed utility capital structure meet the capital attraction and financial integrity requirements of the FRS. The Board is of the view that utility bond metrics do not speak to the issue of whether a ROE determination meets the requirements of the FRS. The Board acknowledges that equity investors have, as the residual, net claimants of an enterprise, different requirements, and that bond ratings and bond credit metrics serve the explicit needs of bond investors and not necessarily those of equity investors.

Finally, the Board questions whether the FRS has been met, and in particular, the capital attraction standard, by the mere fact that a utility invests sufficient capital to meet service quality and reliability obligations. Rather, the Board is of the view that the capital attraction standard, indeed the FRS in totality, will be met if the cost of capital determined by the Board is sufficient to attract capital on a long-term sustainable basis given the opportunity costs of capital. As the Coalition of Large Distributors commented:

> [t]he fact that a utility continues to meet its regulatory obligations and is not driven to bankruptcy is not evidence that the capital attraction standard has been met. To the contrary, maintaining rates at a level that continues operation but is inadequate to attract new capital investment can be considered confiscatory. The capital attraction standard is universally held to be higher than a rate that is merely non-confiscatory. As the United States Supreme Court put it, ‘The mere fact that a rate is non-confiscatory does not indicate that it must be deemed just and reasonable’.[14]

[14] Final Comments of the Coalition of Large Distributors. October 26, 2009. pp. 5-6.

The Role of the Comparable Investment Standard

Continued investment in network utilities does not, in itself, demonstrate that the FRS has been met by a regulator's cost of capital determination, and in particular, whether the determination of the equity cost of capital meets the requirements of the FRS. This is a particular challenge – how does the regulator determine when investment capital is not allocated to a rate regulated enterprise? These decisions are typically made within the utility/corporate capital budgeting process and rarely, if ever, broadly communicated to stakeholders. The Board notes that acquisition and divestiture activities of regulated utilities are not definitive in this regard, one way or the other, and notes that there are many reasons why investors are willing to acquire or desirous of selling utility assets, notwithstanding their view of whether an allowed ROE meets the FRS.

The primary tool available to the regulator to rectify this lack of transparency is the comparable investment standard. By establishing a cost of capital, and an ROE in particular, that is comparable to the return available from the application of invested capital to other enterprises of like risk, the regulator removes a significant barrier that impedes the flow of capital into or out of, a rate regulated entity. The net result is that the regulator is able, as accurately as possible, to determine the opportunity cost of capital for monies invested in utility works, with the ultimate objective being to facilitate efficient investment in the sector.

There are a number of specific issues relating to the comparable investment standard that the Board considers are relevant in the context of this cost of capital policy.

First, "like" does not mean the "same". The comparable investment standard requires empirical analysis to determine the similarities and differences between rate-regulated entities. It does not require that those entities be "the same".

Second, there was a general presumption held by participants representing ratepayer groups in the consultation that Canadian and U.S. utilities are not comparators, due to differences in the "time value of money, the risk value of money and the tax value of money."[15] In other words, because of these differences, Canadian and U.S. utilities cannot be comparators. The Board disagrees and is of the view that they are indeed comparable, and that only an analytical framework in which to apply judgment and a system of weighting are needed. The analyses of Concentric Energy Advisors and Kathy McShane of Foster Associates Inc. are particularly relevant in this regard, and substantially advance the issue of establishing comparability to meet the requirements of the FRS. Further, the Board notes that in the consultation session on October 6, 2009, Dr. Booth stated that it is "absolutely possible" to form a sample from a risky universe that is low risk and compare it to the universe or the population of Canadian utilities.[16] All participants agreed.

The Board notes that Concentric did not rely on the entire universe of U.S. utilities for its comparative analysis. Rather, Concentric carefully selected comparable companies based on a series of transparent financial metrics, and the Board is of the view that this approach has considerable merit. Commenting on Concentric's analysis, Union Gas noted that no one else in the consultation performed this kind of detailed analysis of U.S. comparators.[17] The use of a principled, analytical, and transparent approach to determine a low risk comparator group from a riskier universe for the purpose of informing the Board's judgment was supported by various participants in the consultation.

The PWU commented that the position taken by Dr. Booth on the question of the comparability of US utility returns is not based on an appropriate empirical foundation.[18] The PWU further commented that:

> On the other hand, it is the view of the PWU that the analysis produced by Concentric, as summarized in one of their charts presented at the conference, represents a far more comprehensive analysis of the key characteristics of distribution utilities in Ontario vs. a North American

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[15] Professor L.D. Booth. Written Comments on behalf of Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition, the Industrial Gas Users Association, the Canadian Manufacturers & Exporters (CME), the London Property Management Association and the Building Managers and Owners Association of the Greater Toronto Area. September 8, 2009. p. 25.
[16] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. October 6, 2009. Comments of Dr. Booth at p. 60. Lines 24-26.
[17] Written Comments of Union Gas Limited. October 30, 2009. p. 14.
[18] Final Comments of the Power Workers' Union. October 30, 2009. p. 3.

> proxy group. Differences and similarities were thoroughly considered before arriving at the conclusions that based on a careful selection of like companies, a proxy group which includes US distribution utilities adheres to the Comparable Investment Standard. Moreover, Concentric was better suited to complete such as an analysis, having recognized expertise in the risks faced by both Ontario and US electricity distributors.[19]

Dr. Vander Weide indicated that since Canadian utility bonds tend to have more covenants than US utility bonds, they would receive a slightly higher credit rating. The PWU observed that it the slight variance in ratings can be attributed to specific features of debt instruments, rather than fundamental differences in the underlying business or regulatory risks faced by the utilities. This observation was also made by Ms. Zvarich of Sun Life Financial, who presented evidence that Canadian utility bonds generally have more restrictive covenants than U.S. utility bonds.[20]

The Board is of the view that the U.S. is a relevant source for comparable data. The Board often looks to the regulatory policies of State and Federal agencies in the United States for guidance on regulatory issues in the province of Ontario. For example, in recent consultations, the Board has been informed by U.S. regulatory policies relating to low income customer concerns, transmission cost connection responsibility for renewable generation, and productivity factors for 3rd generation incentive ratemaking.

Finally, the Board agrees with Enbridge that, while it is possible to conduct DCF and CAPM analyses on publicly-traded Canadian utility holding companies of comparable risk, there are relatively few of these companies. As a result, the Board concludes that North American gas and electric utilities provide a relevant and objective source of data for comparison.

[19] Final Comments of the Power Workers' Union. October 30, 2009. p. 6.
[20] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. September 21, 2009. Comments of Ms. Zvarich at pp. 24 -25.

3.2 The Cost of Capital in Theory and Practice

The Cost of Capital

The Ontario Energy Board has been engaged in the rate regulation of utilities for many years. Over this extended period, the Board notes that there continues to be any of a number of misconceptions about the cost of capital concept, particularly what the cost of capital is and why it is an important consideration.

The Board is of the view that the following points articulated by Dr. Bill Cannon in his presentation at CAMPUT's 2009 Energy Regulation Conference on July 3, 2009, are principally relevant to defining and understanding the cost of capital concept.

> At its simplest, the cost of capital is the minimum expected rate of return necessary to attract capital to an investment. The rate of return includes the income received during the time the investment is held plus any capital gain or loss, realized or accruing during this period, all as a percentage of the initial investment outlay.
>
> The cost of capital can be viewed from both: (a) a company or utility perspective; and (b) from the investor's or capital provider's perspective. From the company's perspective, the cost of capital is the minimum rate of return the company must promise to achieve for investors on its debt and equity securities in order to preserve their market values and, thereby, retain the allegiance of these investors.
>
> [There is interest] in the cost of capital…because all utilities – private or public – at some time… must raise financial capital to pay for investments, and both fairness and practical considerations dictate that the private and/or government investors who provide these capital funds must be adequately compensated. Raising capital is a competitive process. Private investors are under no obligation to buy a particular utility's securities, and government-owned utilities must compete with other government spending priorities. A utility will be able to secure new capital and replace maturing securities only if investors believe that they will be adequately rewarded for providing new capital funds. That required reward, in turn, must compensate the investors for a least two things: (1) for postponing the consumption of the goods and services that they might otherwise have enjoyed had they not made the investment; and (2) for exposing their funds to the risk that they may not

> get all their money back or not get it back as promptly as they anticipated. The reward demanded by investors is therefore a necessary cost of doing business from the utility's point of view, just as much as the cost of labour or fuel.
>
> From the viewpoint of investors as a group, however, the cost of capital can be defined more clearly and operationalized as "the expected rate of return prevailing in the capital markets on alternative investments of equivalent risk and attractiveness." There are four concepts embedded in this operational definition:
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> First, it is *forward-looking*. Investment returns are inherently uncertain and the ex post, actual returns experienced by investors may differ from those that were expected ahead of time. The cost of capital is therefore an *expected* rate of return.[21]
>
> Second, it reflects the *opportunity cost* of investment. Investors have the opportunity to invest in a wide range of investments, so the expected rate of return from a given utility-company investment must be sufficient to compensate investors for the returns they might otherwise have received on foregone investments.
>
> Third, it is *market-determined*. This market price - expressed as the expected return per dollar of invested capital - serves to balance the supply of, and demand for, capital for the firm.
>
> And, fourth, it reflects the *risk* of the investment. It reflects the expected returns on investments in the marketplace that are exposed to equivalent risks. Another way of expressing this principle is to say that the cost of capital depends on the *use* of the capital – or, more precisely, the risk associated with the use of the funds – and not on the *source* of the funds.

In Ontario, utilities regulated by the Board in the gas and electricity sectors are structured to operate as commercial entities. As such, the rate setting methodologies used by the Board apply uniformly to all rate-regulated entities regardless of ownership. The determination of rate-regulated entities' cost of capital is no exception. It follows that the opportunity cost of capital should be determined by the Board based on a systematic and empirical approach that applies to all rate-regulated utilities regardless of ownership. The Board sees no

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[21] The word "expected" is used in the statistical sense (i.e., the probability-weighted rate of return). It does not refer to a "hoped for" or "most likely" rate of return.

compelling reason to adopt different methods of determining the cost of capital based on ownership.

The Equity Risk Premium Approach

As previously indicated, the Board has determined that the ERP approach remains the most appropriate approach in the current circumstances. The ERP approach is one of four main approaches that are traditionally used by experts during regulatory cost of capital reviews to establish a fair ROE: (1) the comparable earnings approach; (2) discounted cash flow approach; (3) the capital asset pricing model; and (4) ERP approach. These methods are all used in varying degrees to formulate and/or test an opinion regarding a fair return to investors.[22] The Board's current formulaic approach is a modified Capital Asset Pricing Model methodology and ERP approach.

Each of these four main approaches has well documented strengths and weaknesses. Notwithstanding the known weaknesses of these differing approaches, the Board agrees with Ms. McShane when she states: "each of the various types of tests brings a different perspective to the estimation of a fair return. No single test is, by itself, sufficient to ensure that all three requirements of the fair return standard are met."[23]

Through the consultative process which began in February 2009 and has culminated in this report, the Board has been informed by a number of ex-post analytical approaches, including analysis of experienced ERPs on investments in Canadian utility stocks. The Board observes from these analyses that the ROE produced by various approaches can be expressed as an absolute ROE number or as an ERP over a risk-free rate. Also, the Board agrees that expressing the ROE in terms of a premium above the long-term Canada bond yield does not mean that the initial ROE needs to be estimated by using a single test or a number of tests that might be defined as ERP tests.

[22] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 2.
[23] McShane, K., Foster Associates, Inc. Written comments on behalf of the Electricity Distributors Association. September 8, 2009. p. 2.

A Formulaic Approach

The Board has used a formula-based methodology to determine the rate of ROE since 1998. The advantages identified in the 1997 Draft Guidelines remain appropriate today and include:

- Simplification of the hearing process;
- Is relatively free from conflicting interpretation and is readily understood by all participants;
- Reduces the need for complex, annual risk assessments, while still reflecting major changes in the capital markets; and
- Is capable of producing a rate of return that approximates the result which would have been produced through the traditional process.[24]

The Board also notes that a formula-based approach:

- Is transparent, resulting in predictable and consistent outcomes, and meets the needs of stakeholders broadly, particularly those in the capital market; and
- Is a practical necessity in Ontario, given the large number of rate regulated entities.

The Board also acknowledges that a formula-based ROE methodology and mechanical approaches in general, have a number of disadvantages, as identified in the 1997 Draft Guidelines:

- Establishing the initial parameters of the generic formula will have a profound influence on the potential success or failure of the process. Over time, these parameters and adjustment factors will have a cumulative or compounding effect on the

[24] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 7.

results of the formulaic ROE mechanism. The use of an inappropriate initial ROE will either inflate or understate subsequent rate determinations;

- The present formulaic ROE generally relies predominantly on the ERP method to the exclusion of other methods;

- Adjustment for the impact of timing differences for utilities with different year-ends is a challenge; and

- The Board's ability to make discretionary adjustments to a utility's return for the purpose of creating incentives for particular behaviours or sending signals to the marketplace may be restricted. [25]

Notwithstanding these concerns, the Board is of the view that it is appropriate to continue to use a formulaic approach to determine the equity cost of capital and that the overall advantages of the approach outweigh potential disadvantages.

An Empirical Foundation

The essential elements of a formulaic approach must be empirically derived – the initial ROE, implied ERP and the adjustment factor are determined by the Board based on empirical analysis. It is essential that sufficient empirical analysis be provided periodically to ensure that assumed relationships are not misspecified. This includes the construction and application of a framework to evaluate the degree of comparability between rate regulated natural gas distribution and electricity distribution and transmission utilities in Canada and the United States.

To be clear, the approach to be used by the Board in setting the essential elements of a formula-based rate of ROE (i.e., base ROE, formula terms and adjustment factors) will be based on "economic theory and empirically derived from objective, data-based analysis."[26] As such, it is not sufficient for a formulaic approach for determining ROE to produce a

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[25] Ibid. p. 7.
[26] Ontario Energy Board. Report of the Board on 3rd Generation Incentive Regulation. July 14, 2008. p. 19

numerical result that satisfies the FRS on average, over time. The Board is of the view that each time a formulaic approach is used to calculate an allowed ROE it must generate a result that meets the FRS, as determined by the Board using its experience and informed judgment.

This principle is supported by the *Hope* decision, which states: "Under the statutory standard of 'just and reasonable' it is the result reached not the method which is controlling…"[27]

[27] Federal Power Commission v. Hope Natural Gas 320 U.S. 591 (1944). p. 602

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4 The Board's Approach

4.1 Summary of Key Principles

As discussed previously, the Board confirms the following key principles with respect to its cost of capital policy. The Board has analyzed submissions, discussions at the consultation and the final written comments of participants to the consultation with these general principles in mind.

1. **Fair Return Standard.** All three requirements – comparable investment, financial integrity and capital attraction – must be met and none ranks in priority to the others. It is not sufficient for a formulaic approach for determining ROE to produce a numerical result that satisfies the FRS on average, over time. The Board is of the view that each time a formulaic approach is used to calculate an allowed ROE; it must generate a number that meets the FRS, as determined by the Board using its experience and informed judgment.

2. **The overall ROE must be determined solely on the basis of a company's cost of equity capital**. It does not mean that in determining the cost of capital that investor and consumer interests are balanced. The opportunity cost of capital should be determined by the Board based on a systematic and empirical approach that applies to all rate-regulated utilities regardless of ownership. The Federal Court of Appeal was clear that the overall ROE must be determined solely on the basis of a company's cost of equity capital and that the impact of any resulting toll increase is an irrelevant consideration in that determination.

3. **Efficient amount of investment.** As it relates to a rate regulated entity's cost of capital, the role of the regulator is to determine, as accurately as possible, the opportunity cost of capital to ensure that an efficient amount of investment occurs in the public interest for the purpose of setting utility rates.

4. **Predictability, transparency, and stability**. The approach adopted by the Board to determine the opportunity cost of capital should result in an environment where outcomes are predictable and consistent so that investors, utilities and consumers are better able to plan and make decisions.

5. **Systematic and empirically-based approach**. The methodology used by the Board to determine the cost of debt and equity capital should be a systematic approach that relies on economic theory and is empirically derived from objective, data-based analysis. For example, in establishing comparability, it is possible to build a low-risk sub-set from a higher risk universe using an empirically based approach.

6. **Minimize the time and cost of administering the framework.** Costs imposed on all participants, including the regulated entity and the regulator, should not exceed the benefits available. This objective could be met through a simple process that reflects the concerns of interested participants and reduces the formal process requirements.

4.2 Return on Equity

4.2.1 Need to Reset and Refine Existing ROE Formula

In order to ensure that on an ongoing basis changing economic and financial conditions are adequately and appropriately accommodated in the Board's formulaic approach for determining a utility's equity cost of capital**, the Board has determined that its current formula-based ROE approach needs to be reset and refined**. As previously indicated, **the Board will continue to use a formula-based ERP approach**. However, informed by the discussion at the consultation and the written comments of participants generated by the consultation, as well as its own analysis, the Board has concluded that the formula needs to be reset to address the difference between the allowed ROE arising from the application of the formula and the ROE for a low-risk proxy group that cannot be reconciled based on differences in risk alone. The formula also needs to be refined to reduce its sensitivity to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity.

The Board's current approach to estimating the cost of equity has been in effect for 12 years. The Board notes that in the 1997 Draft Guidelines, the Board stated that "it is persuaded that there exists a non-linear relationship between interest rates and the ERP." [28] The existing formula approximates this relationship using a linear specification. The Board is of the view that it is unreasonable to conclude that the current formula correctly specifies this relationship, based on the passage of time, changes in financial and economic circumstances generally, and the empirical analyses provided by participants to the consultation and the discussion at the consultation itself. However, the Board is of the view that its current formulaic approach for determining the equity cost of capital should be reset and refined, not otherwise abandoned or subject to wholesale change.

The events that unfolded earlier this year that triggered this review effectively illustrated that the Board's approach needs to be refined to reduce the sensitivity of the formula to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity. The Board concludes that the current approach could be more robust and better guide the Board's discretion in applying the FRS. The Board notes that while the current formula today produces results similar to that in 2008, it does not address the observed behaviour of the formula during the financial crisis – lowering the allowed ROE when the amount and price of risk in the market was increasing.

The view expressed by some participants in the consultation that the Board must wait to be provided with evidence from a regulated utility in Ontario of financial hardship due to the current allowed ROE before its adapts its policies to better reflect market realities is not consistent with the Board's approach.

The Board is of the view that resetting and refining the current formula-based ERP approach maintains the transparency, predictability and stability associated with the current

[28] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 31.

approach, and avoids sudden changes in regulatory policy to address potentially transitory capital market conditions. [29]

The Board has been informed by the numerous approaches used by various participants to the consultation to determine whether the formula continues to produce results that meet the FRS. The sum of the elements supporting the Board's decision to reset and refine its formulaic ROE is independent of the recent financial crisis and whether or not the crisis has abated.

4.2.2 The Initial Set Up

Use of Multiple Tests

The Board's current formulaic approach for determining ROE is a modified Capital Asset Pricing Model methodology, and in his written comments, Dr. Booth recommended that this practice be continued. Dr. Booth recommended that "the Board base its fair ROE on a risk based opportunity cost model, with overwhelming weight placed on a CAPM estimate"[30].

This view was not shared by other participants in the consultation, who asserted that the Board should use a wide variety of empirical tests to determine the initial cost of equity, deriving the initial ERP directly by examining the relationship between bond yields and equity returns, and indirectly by backing out the implied ERP by deducting forward-looking bond yields from ROE estimates.

Participants argued from a number of different perspectives that a variety of methods should be used to develop the ERP:

- "The Board should not limit itself to one specific method of calculating an ERP; rather it should consider the results produced by multiple approaches in order to

[29] Written Comments of the Industrial Gas Users Association, October 30, 2009, p. 2.
[30] Ibid. p. 20.

generate a range of reasonable results from which it may select an appropriate ERP. This process requires the exercise of informed judgment”[31].

- “The Board established the initial risk premium for the Formula, in its decision for Consumers Gas in EBRO 495, by considering an array of risk premium estimates put forward by experts and selecting a risk premium within the range of results presented. The risk premiums put forth by experts were either the result of directly measuring the historical relationship between bond yields and equity returns; or alternatively, by deriving an implied risk-premium, by backing-out forward looking bond yields from ROE estimates produced by using other methodologies, i.e., DCF, CAPM, or Comparable earnings.

  Multiple approaches for determining ROE provide greater assurance that the end result will be just and reasonable, as conditions that may bias results could be detected or mitigated by considering alternative results.”[32]

- “The Board should consider comparable utilities’ rates of return and a minimum spread to long-term debt rates, as well as resetting the reference rate”.[33]

- “The Board should establish the initial ROE by looking at the best available evidence on the utilities’ required return. This evidence should include results of various cost of capital methodologies…The Board would be remiss to predetermine a single methodology for establishing the initial allowed ROE without reviewing alternative methods for determining cost of equity.” [34]

- “We propose that the Board, in reviewing cost of capital, would hear the evidence of the various experts with their different views of the ERP result, but would also look at

[31] Concentric Energy Advisors. Written Comments on behalf of Enbridge Gas Distribution, Hydro One, and the Coalition of Large Distributors, September 8, 2009. September 8, 2009. p. 59.
[32] Ibid. p. 47.
[33] Written Comments of the Power Workers’ Union. September 8, 2009. p. 6.
[34] Dr. J. H. Vander Weide. Written Comments on behalf of Union Gas. pp. 7-8.

other ways in which the market directly speaks about returns…they (the examples provided) and many other examples – are ways in which the market communicates the returns for investment comparable to utility investments. These sources are therefore useful in testing whether the results of various ERP or other market studies of cost of capital are realistic." [35]

- "If the utility is not a stand-alone entity and/or does not have traded shares, then the Board has no alternative but to look at total rates of return earned by investors in a relevant sample of companies." [36]

- "Expressing the ROE in terms of a premium above…long-term Canada bond yield… does not mean that the initial ROE need be estimated solely using a test or tests that might be defined as ERP tests." [37]

  "No single model is powerful enough to produce 'the number' that will meet the fair return standard. Only by applying a range of tests along with informed judgment can adherence to the fair return standard be ensured." [38]

- "…use of multiple tests. The tests all measure different factors that should be considered in setting a fair return on equity that is consistent with the comparable investment standard, the financial integrity standard and the capital attraction standard. The OEB should not rely on a single method or test." [39]

The Board agrees that **the use of multiple tests to directly and indirectly estimate the ERP is a superior approach to informing its judgment than reliance on a single methodology**. In particular, the Board is concerned that CAPM, as applied by Dr. Booth, does not adequately capture the inverse relationship between the ERP and the long

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[35] Written Comments of the School Energy Coalition. September 2009. pp. 2-3.
[36] Written Comments of Energy Probe Research Foundation. September 8, 2009. p. 14.
[37] McShane, K., Foster Associates, Inc. Written Comments on behalf of the Electricity Distributors Association. September 8, 2009. p. 2.
[38] Ibid. p. 23.
[39] Written Comments of Ontario Power Generation Inc. September 8, 2009. p. 3.

Canada bond yield. As such, the Board does not accept the recommendation that it place overwhelming weight on a CAPM estimate in the determination of the initial ERP.

Setting the Initial Equity Risk Premium

The Board is of the view that the initial ERP should be reset to address the difference between the allowed ROE arising from the application of the formula and the ROE for a low risk proxy group that cannot be reconciled based on differences in risk alone.

Therefore, based on the ERP recommendations provided by all participants in this consultation the **Board has determined that an initial ERP of 550 basis points** is appropriate for the purposes of deriving the initial ROE to be embedded in the Board's reset and refined ROE formula. This includes an implicit 50 basis points for transactional costs.

Consequently, **assuming a forecast long term government of Canada bond yield of 4.25%, the initial ROE to be embedded in the Board's reset and refined ROE formula will be 9.75%** (i.e., 4.25% + 550 basis points = 9.75%).

The Board has assessed the various empirical tests and recommendations submitted by participants and translated each of the recommended approaches as an ERP assuming a forecast long term government of Canada bond yield of 4.25%, where appropriate, as summarized in Table 1.

The empirical tests of each of the participants to the consultation are also described below. Although the Board maintains its view that each of the tests has empirical strengths and weaknesses, the diversity of approaches tabled and discussed in the consultation was helpful. As a result, the Board has given each test weight in the process to establish the initial ERP to be embedded in the Board's formula.

Table 1: Summary of Participant Recommendations

Direct/Indirect Equity Risk Premium	Low	Medium	High
Dr. L.D. Booth			
CAPM (Adjusted Using CoC Formula to Reflect 4.25% GOC, 0.75 Adj)	3.31%	3.31%	3.31%
Average Dr. L.D. Booth	**3.31%**	**3.31%**	**3.31%**
Concentric Energy Advisors			
DCF Analysis for Low-Risk Proxy Group (US Gas, Elec, Cdn)	6.03%	6.78%	7.83%
CAPM Analysis for Low-Risk Proxy Groups (US Gas, US Elec, Cdn)	4.58%	4.72%	4.86%
ERP Econometric Model (Average Gas and Electric)	6.35%	6.35%	6.35%
Average Concentric Energy Advisors	**5.65%**	**5.95%**	**6.35%**
J. Dalton - Power Advisory LLC			
ERP Econometric Model #1 and ERP Econometric Model #2	6.05%	6.45%	6.85%
Average J. Dalton - Power Advisory	**6.05%**	**6.45%**	**6.85%**
K. McShane - Foster Associates			
New Formula for Calculating Allowed ROE (NEB Initial Formula Metrics)	6.38%	6.38%	6.38%
Illustrative method	5.75%	5.75%	5.75%
Average: K. McShane	**6.07%**	**6.07%**	**6.07%**
Dr. J.H. Vander Weide			
Experienced Equity Risk Premium	4.30%	5.50%	6.60%
2008 Awarded ROEs Vs. Avg 2008 US LT T-Bills - Gas	6.16%	6.16%	6.16%
2006-8 Awarded ROEs Vs. Avg 2006-8 US LT T-Bills - Gas	5.61%	5.61%	5.61%
2008 Awarded ROEs Vs. Avg 2008 US LT T-Bills - Electric	6.26%	6.26%	6.26%
2006-8 Awarded ROEs Vs. Avg 2006-8 US LT T-Bills - Electric	5.71%	5.71%	5.71%
Forecast $E(R_e)$ = DCF Expected Return - LT Treasury Yield			
Gas	6.19%	6.19%	6.19%
Electric	6.21%	6.21%	6.21%
Regression - Ex-ante ERP (Above) with YTM LT Treasury Yields			
Gas (Modified to use Canadian LT GOC bond)	6.97%	6.97%	6.97%
Electric (Modified to use Canadian LT GOC bond)	7.33%	7.33%	7.33%
DCF Analysis for Value Line Utility Companies			
Gas	7.81%	7.81%	7.81%
Electric	8.71%	8.71%	8.71%
Average: Dr. J.H.Vander Weide	**6.48%**	**6.59%**	**6.69%**
Average ERP All Submissions	**5.51%**	**5.67%**	**5.85%**

Analyses of Dr. J. H. Vander Weide

Dr. Vander Weide performed a number of empirical analyses. The average experienced ERP on an investment in Canadian utility stocks from data on returns earned by investors in Canadian utility stocks compared to interest rates on long-term Canada bonds was approximately 5.50 percent, as set out below:

Comparable Group	Period of Study	Average Stock Return	Average Bond Yield	Risk Premium
S&P/TSX Utilities	1956 - 2008	11.84%	7.54%	4.3%
BMO CM Utilities Stock Data Set	1983 - 2008	14.31%	7.66%	6.6%
Average				**5.5%**

Source: Written comments of Dr. J.H. Vander Weide. Page 14.

He also provided information on recent allowed ROEs for U.S. utilities which demonstrated implicit ERPs:

	Natural Gas Distribution		Electric Utilities	
	2008	**2006 - 2008**	**2008**	**2006 - 2008**
Average U.S. ROE Awarded (%)	10.4	10.3	10.5	10.4
Spread to OEB September 2009 Long Bond Estimate of 4.25%	6.15	6.05	6.25	6.15
Spread to Average Long-Term Canada Bond Yield in 2008 of 4.06%	6.34	NA	6.44	NA
Spread to Average Long-Term Canada Bond Yield in 2006 to 2008 of 4.21%	NA	6.09	NA	6.19
Spread to Average Long-Term U.S. Treasury Bill Yield in 2008 of 4.24%	6.16	NA	6.26	NA
Spread to Average Long-Term U.S. Treasury Bill Yield in 2006 to 2008 of 4.69%	NA	5.61	NA	5.71

Sources: Government of Canada Bond Yields: Bank of Canada; U.S. Long-Term Treasury Bill Yields: U.S. Department of Treasury

Further, forecast expected required returns by investors were calculated by Dr. Vander Weide by deducting the long-term Treasury bond yield from the DCF expected return (Exhibit 5, Dr. Vander Weide) over the period September 1999 to February 2009. This calculation produced an average ERP of 621 basis points for electric utilities and an average expected ERP of 619 basis points for natural gas utilities (Exhibit 6, Dr. Vander Weide) over the period June 1998 to February 2009.

However, regressing the relationship between the *ex ante* risk premium and the yield to maturity on long-term U.S. Treasury bond produced an ERP equation of:

- ERP = 12.10 – 1.123 x I_B for Electric Utilities. Assuming an estimated Canadian Long-Term Bond yield of 4.25%, the Ex-Ante expected ERP is 7.33% and an ROE of 11.58%; and

- ERP = 10.26 – 0.773 x I_B for Natural Gas Distribution Utilities. Assuming an estimated Canadian Long-Term Bond yield of 4.25%, the Ex-Ante expected ERP is 6.97% and an ROE of 11.22%.

Finally, Dr. Vander Weide conducted a DCF Analysis for Value Line Natural Gas Companies that resulted in an estimated ROE of 11.5% (Exhibit 9, Dr. Vander Weide) or an ERP of approximately 7.81%, using the average February 2009 long-term composite Treasury bond yield of 3.69%. His DCF Analysis for Value Line Electric Companies (Exhibit 8, Dr. Vander Weide) resulted in an estimated ROE of 12.4% or an ERP of approximately 8.71%, assuming the same long-term composite Treasury bond yield.

Analysis of Kathy McShane of Foster Associates Inc.

Ms. McShane proposed a new formula for calculating the allowed ROE: ROE_{New} = Initial ROE + 50% (Change in Forecast GOC Bond Yield) + 50% (Change in Corporate Bond Yield Spread), which reflects the analysis provided in her comments.

Ms. McShane also demonstrated that using her recommended approach for 2009, based on the NEB formula contained in RH-2-94 Decision, the ROE would have been 10.73%[40], equal to an ERP of 638 basis points and assuming a forecast GOC yield of 4.35% for 2009.

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[40] McShane, K., Foster Associates Inc. Written Comments on behalf of the Electricity Distributors Association. Schedule 4.

For illustrative purposes in her analysis, she linked a forecast long-term Canada bond yield of 4.5% and a corporate bond yield spread of 175 basis points to an ROE of 10%. Implied in this ROE is an ERP of 550 basis points.

Analysis of Power Advisory LLC

Power Advisory evaluated a range of different model specifications in an effort to come up with a formula that will yield more reasonable results than the existing formula under a range of different credit and financial market conditions.[41] Two models performed the best in terms of standard econometric considerations (i.e., goodness of fit, highly significant parameter values, and plausible statistical relationships)[42]:

1. ROE = 7.008% + (US Corp BAA Bond Yield with 6 month lag x 0.5356); and
2. ROE = 7.451% + (US Gov 30 Year Bond yield with 6 month lag x 0.5122) + (VIX index value with 6 month lag x 0.0077).

Using current values for these variables produces ROE estimates of 10.5% to 11.3%. Using Canadian values in these models results in ROE estimates of 10.3% to 11.1%. The implied ERP using the results of the models run using a forecast long-term government of Canada bond yield of 4.25% is 605 basis points to 685 basis points.

Analysis of Concentric Energy Advisors

Concentric's overall recommended ROE for natural gas distribution utilities, assuming a 40% deemed equity capital structure is 10.5% and for electric transmission and distribution utilities is 10.3%, also assuming 40% deemed equity. The implied ERP assuming a 4.25% forecast GOC bond yield is 625 basis points and 605 basis points, for natural gas and electric transmission and distribution, respectively. These recommendations are supported by multiple analytical approaches; each calculated using data for a specific proxy group for

[41] Power Advisory LLC. Written Comments on behalf of Great Lakes Power Transmission LP. September 8, 2009. p. 16.
[42] Ibid. p. 17.

the natural gas and electric transmission and distribution utilities established by Concentric.[43]

The results of Concentric's DCF analysis are presented in the table below[44].

Proxy Group	Low	Mean	High
U.S. Natural Gas Distribution Utilities	9.70%	10.44%	11.57%
U.S. Electric Distribution Utilities	10.08%	10.96%	12.09%
Canadian Utilities	9.97%	10.60%	11.47%
Average	9.92%	10.67%	11.71%
Implied ERP at 4.25% forecast LT GOC Yield	5.67%	6.42%	7.46%
Implied ERP Including 50 basis points Flotation Costs	**6.17%**	**6.92%**	**7.96%**

The results of Concentric's CAPM analysis are presented in the table below. The results reflect a Market Risk Premium of 586 basis points, which is supported by material provided in Appendix F (page F-10) and Exhibit Concentric-06 of their written comments.

Proxy Group	Low	Mean	High
U.S. Natural Gas Distribution Utilities	9.05%	9.18%	9.32%
U.S. Electric Distribution Utilities	8.54%	8.68%	8.82%
Canadian Utilities	7.80%	7.95%	8.10%
Average	8.46%	8.61%	8.75%
Implied ERP at 4.25% forecast LT GOC Yield	4.21%	4.36%	4.50%
Implied ERP Including 50 basis points Flotation Costs	**4.71%**	**4.86%**	**5.00%**

The results of Concentric's ERP analysis are presented in the table below and are explained in detail in Appendix F of their written comments.

[43] Concentric Energy Advisors. Written Comments on behalf of Enbridge Gas Distribution, Hydro One, and the Coalition of Large Distributors. September 8, 2009. Appendix C.
[44] Ibid. p. F-6.

Concentric's ERP regression formula is as follows: ROE = Constant = U.S. Gov 30-year Bond • x_1 + Moody's Utility A-rated Spread • x_2 + % Generation • x_3 + Natural Gas Dummy Variable • x_4.[45]

	U.S. Natural Gas Distribution Proxy Group	**U.S. Electric Distribution Proxy Group**
Constant	7.634	7.634
U.S. Government 30-year Bond Yield	0.428 x 4.18	0.428 x 4.18
Moody's Utility A-rate Spread (July 2009)	0.310 x 1.56	0.310 x 1.56
% Generation	0.008 x 0.00	0.008 x 49.76
Natural Gas Dummy (Electric = 0,Gas = 1)	0.384 x 1.00	0.384 x 0.00
Authorized ROE	10.29%	10.30%
Implied ERP at 4.25% forecast LT GOC Yield	6.04%	6.05%
Implied ERP Including 50 basis points Flotation Costs	**6.54%**	**6.55%**

The tables below summarize Concentric's recommended ROEs prior to any adjustment for changes in leverage:[46]

U.S. Electric T & D Utilities	**Low**	**Mean**	**High**
DCF	10.08%	10.96%	12.09%
CAPM	8.54%	8.68%	8.82%
Average	9.31%	9.82%	10.46%
Differential between Vertically Integrated and T&D Utilities	(0.40%)	(0.40%)	(0.40%)
Return before Leverage and Flotation Cost Adjustments	8.91%	9.43%	10.06%
Flotation Cost Adjustment 0.50%	0.50%	0.50%	0.50%
Benchmark T&D ROE	9.41%	9.93%	10.56%
Benchmark T&D Equity Ratio	46.32%	46.32%	46.32%
Implied ERP using 4.25% forecast LT GOC Yield	5.16%	5.68%	6.31%

U.S. Natural Gas Distribution Utilities	**Low**	**Mean**	**High**
DCF	9.70%	10.44%	11.57%
CAPM	9.05%	9.18%	9.32%
Return before Leverage and Flotation Cost Adjustments	9.37%	9.81%	10.45%
Flotation Cost Adjustment 0.50%	0.50%	0.50%	0.50%
Benchmark Natural Gas Distribution ROE	9.87%	10.31%	10.95%
Benchmark Natural Gas Distribution Equity Ratio	44.47%	44.47%	44.47%
Implied ERP using 4.25% forecast LT GOC Yield	5.62%	6.06%	6.70%

Adjusting for leverage that is higher than the benchmark equity ratio, i.e., deemed equity of 40%, the recommended ROEs increase to 10.5% for natural gas distribution and 10.3% for electric transmission and distribution, representing implied ERPs of 625 basis points and 605 basis points, respectively.

[45] Ibid. p. F-14.
[46] Ibid. p. F-16.

Analysis of Dr. Booth

Dr. Booth recommended a fair ROE of 7.75%. This number is based on the following key assumptions.[47]

First, a market risk premium of 5.0%. However, Dr. Booth noted that many of his peers believe it to be 6.0%. Second, beta is estimated to be 0.5. Dr. Booth indicated that he "is not using the current beta coefficient"[48]; i.e., the beta of 0.5 used to derive the recommended ERP of 325 (assuming a 4.50% long-term government of Canada bond yield) is not supported by Dr. Booth's recent beta estimates, where beta is less than 0.5. Thirdly, Dr. Booth also noted that the range of fair return cost of equity estimates could vary by 0.50%. His unadjusted estimate of a fair return was 7.00% and he noted that the estimates of his colleagues would be 7.50%. He therefore added 0.25% to his estimate to "split this difference", resulting in his ROE recommendation of 7.25%. Finally, Dr. Booth added 0.50% for issuance costs, bringing his fair recommended return to 7.75%.

The Board notes that in the course of the consultation, Dr. Booth indicated that he would be prepared to recommend "fixing ROE at 8.5% or 8.75% over the business cycle, for say, a five-year period."[49] Dr. Booth did not support this estimated ROE with empirical analysis, and as such, there is no principled basis upon which the Board can rely on Dr. Booth's recommendation of 8.5% or 8.75%.

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[47] Professor L.D. Booth. Written Comments on behalf of Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition, the Industrial Gas Users Association, the Canadian Manufacturers & Exporters, the London Property Management Association and the Building Managers and Owners Association of the Greater Toronto Area. September 8, 2009. p. 40.
[48] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. October 6, 2009. p. 100. Lines 12 and 13.
[49] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. October 6, 2009. p. 98. Lines 10 – 12.

4.2.3 The Formula-based Return on Equity

4.2.3.1 Long Canada Bond Forecast

The Board is of the view that the LCBF continues to be an appropriate base upon which to begin the ROE calculation. In particular, the Board is of the view that the sensitivity of the allowed ROE to changes in government of Canada bond yields arising from monetary and fiscal conditions that do not reflect changes in utility cost of equity will be addressed, in part, by the use of multiple methods to determine the initial ERP or ROE in the formula. The Board also agrees with Ms. McShane's comment that the LCBF provides an important forecast component to the formula[50] and with the Industrial Gas Users Association's comment that "there is an intrinsic logic to using the same parameter to adjust ROE as was used to set the ROE in the first place."[51]

4.2.3.2 Long Canada Bond Forecast Adjustment Factor

In its 1997 Draft Guidelines, the Board determined that the difference between the LCBF for the current test year and the corresponding rate for the immediately preceding year should be multiplied by a factor of 0.75 to determine the adjustment to the allowed ROE.[52] In that same document, however, the Board noted that there was a significant difference of opinion concerning the relationship between interest rates and the ERP and that ratios contained in the evidence from generic rate of return proceedings in other Canadian jurisdictions ranged from 0.5:1 to 1:1.[53] Moreover, the Board notes that the selection of the 0.75 adjustment factor is described in the 1997 Draft Guidelines as "admittedly somewhat arbitrary."[54]

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[50] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. September 22, 2009. Ms. McShane's presentation, pp. 161-162;
[51] Final Written Comments of the Industrial Gas Users Association. October 30, 2009. p. 10.
[52] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities, March 1997. p. 31.
[53] Ibid.
[54] Ibid. p. 32.

The Board views **the determination of the LCBF adjustment factor to be an empirical exercise, and as such, based on the empirical analysis provided by participants in conjunction with the consultation, the Board is of the view that the LCBF adjustment factor should be set at 0.5**. The Board notes that four participants in this consultation empirically tested the relationship between government bond yields and ROE:

- Dr. Vander Weide determined that when the yield to maturity on long-term government bonds increases by 100 basis points, the allowed ERP tends to decrease by approximately 55 basis points, and when the yield to maturity on long-term government bonds decreases by 100 basis points, the allowed ERP tends to increase by approximately 55 basis points.[55]

- Kathy McShane of Foster Associates, Inc. submitted that a regression analysis used to estimate the relationship between government bond yields and the utility cost of equity indicates that the ROEs increased (decreased) by approximately 50 basis points for every one percentage point increase (decrease) in long-term government bond yields.[56]

- Concentric Energy Advisors also conducted a regression analysis in which the litigated ROEs of U.S. LDC utility returns demonstrated an elasticity factor to government bond yields of 0.45. This implies that the risk premium should have actually increased by approximately 0.55 for each percentage point drop in the government bond yield (as opposed to the 0.25 implied by the current formula).[57]

[55] Dr. J.H. Vander Weide. Written Comments on behalf of Union Gas. September 8, 2009. p. 21.
[56] K. McShane. Foster Associates, Inc. Written Comments on behalf of the Electricity Distributors Association. September 8, 2009. p. 26.
[57] Concentric Energy Advisors. Written Comments on behalf of Enbridge Gas Distribution, Hydro One, and the Coalition of Large Distributors. September 8, 2009. pp. 41-42.

- John Dalton of Power Advisory also used a regression analysis to determine that the ERP changes by less than 50% of the change in the long-term government bond rate.[58]

The Industrial Gas Users Association also stated that it sees some merit in further consideration of adjusting downwards to 0.5 the coefficient for application of changes in long Canada bond yields to ROE.

4.2.3.3 Additional Term – Changes in Utility Bond Spread

The Board is of the view that the sensitivity of the formula to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in the utility cost of equity is addressed, in part, by using multiple methods to determine the initial ERP and ROE in its formulaic ROE approach and by reducing the LCBF adjustment factor to 0.5 from 0.75. The Board also is of the view, however, that **the specification of the relationship between interest rates and the ERP in the formula would be improved by the addition of a further term to the formula**.

In particular, the Board is of the view that there is a relationship between corporate bond yields and the equity return, and the Board agrees with Dr. Booth, who stated, with respect to corporate bond spreads, that "this is not to say that spreads have no information about required risk premium."[59] The Board notes that three participants to the consultation conducted empirical analysis to specify the relationship between corporate bond yields and the equity return:

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[58] Power Advisory LLC. Written Comments on behalf of Great Lakes Power Transmission LP. April 17, 2009. p. 15.

[59] Professor L.D. Booth. Written Comments on behalf of Consumers Council of Canada, the Vulnerable Energy Consumer's Coalition, the Industrial Gas Users Association, the Canadian Manufacturers & Exporters (CME), the London Property Management Association and the Building Managers and Owners Association of the Greater Toronto Area. September 8, 2009. p. 29.

- Concentric demonstrated by using a regression analysis that there is a statistically significant relationship between ROE and corporate bond yields and specified that the sensitivity of allowed returns to corporate bond yields is about 0.45 to 0.55[60]. Concentric also demonstrated empirically that Treasury bonds have been more volatile than corporate bonds since January 1997.

- Kathy McShane of Foster Associates tested the relationship between corporate bond yields and the utility cost of equity. She determined the cost of equity using two approaches: first, by using approved returns on equity for utilities not governed by formulas as a proxy for the utility cost of equity, and second, by relying on a time series of utility costs of equity developed by using the discounted cash flow approach against which yields on utility bonds can be compared[61]. By using regression analysis, Ms. McShane determined that allowed ROEs have increased (decreased) by approximately 45 basis points for every one percentage point increase (decrease) in the A rated utility bond yield. Similarly, the DCF cost of equity increased (decreased) by approximately 55 basis points for every one percentage point increase (decrease) in long-term A rated utility bond yields.[62]

- John Dalton from Power Advisory LLC conducted an econometric analysis, which established that the relationship between ROE and U.S. corporate BAA bond yields with a six month lag is approximately 0.53.[63]

Based on the analysis provided by participants to the consultation, the Board concludes that **there is a statistically significant relationship between corporate bond yields and the cost of equity, and that a corporate bond yield variable should be incorporated in the ROE formula**. The Board notes that the presence of a corporate bond yield variable in its

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[60] Concentric Energy Advisors. Written Comments on behalf of Enbridge Gas Distribution, Hydro One, and the Coalition of Large Distributors. September 8, 2009. pp. 53–55.
[61] K. McShane. Foster Associates, Inc. Written Comments on behalf of the Electricity Distributors Association. September 8, 2009. p. 25.
[62] Ibid. p. 26.
[63] Power Advisory LLC. Written Comments on behalf of Great Lakes Power Transmission LP. September 8, 2009. p. 17.

current ROE formula would have served to increase the allowed ROE during the recent credit crisis, which, in the Board's view, would have been directionally correct.[64]

The Board has determined that it is appropriate to use a corporate yield variable that is reflective of the borrowing costs of Canadian utilities, one that is well-understood and is based on an established index from a recognized source. **The Board has** accordingly **determined that it will use a utility bond spread based on the difference between the Bloomberg Fair Value Canada 30-Year A-rated Utility Bond index yield and the long Canada bond yield.** This is further described in Appendix B.

The Board agrees with the comment of Ms. McShane that separating the LCBF and the utility bond spread variables, as opposed to using one corporate bond yield variable that would implicitly incorporate the LCBF, provides transparency as it shows "what part is causing the ROE to move in either direction."[65]

The Board also determines that the utility bond spread reflected in the reset and refined formulaic ROE approach will be subject to a 0.50 adjustment factor, consistent with the empirical analyses provided by participants to the consultation.

4.3 Capital structure

The Board's current policy with regard to capital structure for all regulated utilities continues to be appropriate. As noted in the Board's draft guidelines, capital structure should be reviewed only when there is a significant change in financial, business or corporate fundamentals. [66] The Board's current policy is as follows:

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[64] Written Comments of the Electricity Distributors Association. September 8, 2009. Schedule 4.
[65] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. Ms. McShane's presentation, p. 161.
[66] Ontario Energy Board. Ontario Energy Board Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 2

- The Board has determined that a split of 60% debt, 40% equity is appropriate for all electricity distributors. [67] Capital structure was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely supported the continuation of the Board's existing policy.

- For electricity transmitters, generators, and gas utilities, the deemed capital structure is determined on a case-by-case basis. The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk. [68]

4.4 Debt Rates

4.4.1 Long-term debt

The determination of the cost of long-term debt was not a primary focus of the consultation and the Board notes that the comments made by participants in the consultation largely supported the continuation of the Board's existing policies and practices.

While the Board agrees with this approach, it is important to note that the determination of the cost of long-term debt has typically received significant interest in the processes to establish electricity distribution and, to a lesser extent, electricity transmission rates. In contrast to the difficulty establishing the utility cost of equity that arises from a lack of transparency, the issues associated with the determination of a utility's long-term debt cost arise from different factors, including the relatively short period of time since the corporatization of electricity distribution and transmission utilities, the relatively short history of rate regulation by the Board, and the presence of significant amounts of affiliate debt.

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[67] Ontario Energy Board. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors. December 20, 2006. p. 5
[68] Ontario Energy Board. Compendium to Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March, 1997. p. 30

Natural gas distributors

The Board has a long history of determining the cost of long-term debt for natural gas distributors. Based on this experience and in the absence of any material comments in the consultation suggesting otherwise, the Board is of the view that **the current policy of using the weighted cost of embedded debt should continue**. Consistent with the current practice, in a forward test year rate application the onus is on the applicant utility to forecast the amount and cost of new long-term debt. These values are then factored into the estimated cost of existing long-term debt for the purpose of setting regulated natural gas distribution rates. Debt instruments and debt rates are subject to a prudence review in an application for rates. However, it is the Board's policy that the total estimated cost of debt should be a close proxy for the actual long-term debt cost incurred by the natural gas utility in the rate year.

OPG's prescribed rate-regulated baseload generation

Consistent with the Board's practice in OPG's 2008 Cost of Service application, considered under Board file number EB-2007-0905, the Board is of the view that **OPG's cost of long-term debt should be set in a manner similar to that adopted for natural gas distributors**.

Electricity transmitters

Consistent with the Board's current practice as set out in various Decisions and Orders arising from rate applications by electricity transmitters, the Board is of the view that **an electricity transmitter's cost of long-term debt should be set in a manner similar to that adopted for natural gas distributors**.

Electricity distributors

In the 2000 Electricity Distribution Rate Handbook, the Board adopted deemed long-term debt rates and deemed capital structures that varied based on the size of utility rate base.

The deemed long-term debt rates applied regardless of a utility's actual cost of debt and actual capitalization. This deemed approach reflected the ongoing corporatization of the sector and the fact that many electricity distribution utilities had no debt.

The *2006 Electricity Distribution Rate Handbook*, issued by the Board on May 11, 2005, documented an evolution of the treatment of long-term debt for electricity distributors. While the size-related capital structure and (updated) deemed debt rates were retained, the handbook outlined that long-term debt costs could also reflect the cost of embedded debt. The cost of affiliate debt was also capped by the deemed debt rate at the time of issuance.

In April of 2006, Board Staff undertook research, commissioned expert advice and consulted with stakeholders on the methods for setting the cost of capital and 2nd Generation Incentive Rate Making. These consultative activities culminated in the December 20, 2006 Report. In that report, the Board provided additional guidance on the treatment of long-term debt, and emphasized that while there should be increased reliance on actual or embedded debt costs, the need for a deemed debt rate that would continue to apply (either in itself or as a ceiling on affiliate debt) was recognized.

In distribution utility rate applications heard by the Board since the issuance of the December 20, 2006 Report, the Board has made determinations on the treatment of long-term debt that not only reflect the 2006 guidelines, but are based on the record before it in each application. The Board has also been informed by the findings made in relation to completed applications. **The Board is of the view that it is appropriate for this cost of capital policy to reflect the current practices of the Board with respect to determining the cost of long-term debt based on recent Board decisions**.

The following guidelines on the treatment of long-term debt are intended to provide more certainty for applicants and all participants in general. **The Board wishes to emphasize that the long-term debt guidelines relating to electricity distribution utilities are expected to evolve over time and are expected to converge with the process used by the Board to determine the amount and cost of long-term debt for natural gas distributors**. The Board recognizes that there is still a need for the deemed long-term debt rate, however its usage should become more limited in application. The Board wishes to reiterate that the onus is on the distributor that is making an application for rates to document the actual amount and cost of embedded long-term debt and, in a forward test year, forecast the amount and cost of new long-term debt to be obtained during the test year to support the reasonableness of the respective debt rates and terms.

The following guidelines are relevant with respect to the determination of the amount and cost of long-term debt for electricity distribution utilities.

The Board will primarily rely on the embedded or actual cost for existing long-term debt instruments. The Board is of the view that electricity distribution utilities should be motivated to make rational decisions for commercial "arms-length" debt arrangements, even with shareholders or affiliates.

In general, the Board is of the view that the onus is on the electricity distribution utility to forecast the amount and cost of new or renewed long-term debt. The electricity distribution utility also bears the burden of establishing the need for and prudence of the amount and cost of long-term debt, both embedded and new.

Third-party debt with a fixed rate will normally be afforded the actual or forecasted rate, which is presumed to be a "market rate". However, the Board recognizes a deemed long-term debt rate continues to be required and this rate will be determined and published by the Board. **The deemed long-term debt rate will act as a proxy or ceiling for what would be considered to be a market-based rate by the Board in certain circumstances**. These circumstances include:

- For affiliate debt (i.e., debt held by an affiliated party as defined by the Ontario *Business Corporations Act, 1990*) with a fixed rate, the deemed long-term debt rate <u>at the time of issuance</u> will be used as a ceiling on the rate allowed for that debt.

- For debt that has a variable rate, the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. This applies whether the debt holder is an affiliate or a third-party.

- The deemed long-term debt rate will be used where an electricity distribution utility has no actual debt.

- For debt that is callable on demand (within the test year period), the deemed long-term debt rate will be a ceiling on the rate allowed for that debt. Debt that is callable, but not within the period to the end of the test year, will have its debt cost considered as if it is not callable; that is the debt cost will be treated in accordance with other guidelines pertaining to actual, affiliated or variable-rate debt.

- A Board panel will determine the debt treatment, including the rate allowed based on the record before it and considering the Board's policy (these Guidelines) and practice. The onus will be on the utility to establish the need for and prudence of its actual and forecasted debt, including the cost of such debt.

Deemed Long-term Debt Formula for Electricity Distributors

While the Board is of the view that greater reliance should be placed on embedded debt, including forecasts of the amount and cost of new debt expected to be incurred during the test year, the Board recognizes that there is a continuing need for a deemed long-term debt rate.

While there were no specific suggestions for how the deemed long-term debt rate should be calculated, **the Board sees merit in modifying the formula in a manner consistent with the changes adopted for the ROE adjustment formula**.

Specifically, the Board considers that **the deemed long-term debt rate for the test year should be an estimate based on the long (30-year) Government of Canada bond yield forecast plus the average spread between an A-rated Canadian utility bond yield and 30-year Government of Canada bond yield for all business days in the month three (3) months in advance of the (proposed) effective date for the rate changes**. This change is only in the source of the data, in the following ways:

- The 30-year A-rated Canadian utility bond yield data from Bloomberg will replace the BBB/A-rated Canadian Corporate bond yield series that was obtained from PC Bond, an affiliate of TSX.[69]

- The monthly average of business daily data will be used, instead of the weekly data used previously.

The changes are due to the data availability, and to transparency and cost. Both Bloomberg and PC Bond corporate bond series are proprietary and available on subscription bases. Using the same A-rated Canadian utility bond yield series from Bloomberg will reduce costs and work and increase transparency of the calculations. The Board does not consider the changes in methodology will have any material impact on the calculated deemed long-term debt rate. The Board also notes that this methodology was supported by LPMA and BOMA in their final written comments.[70]

Appendix C provides a detailed description of the methodology for calculating the deemed long-term debt rate.

4.4.2 Short-term debt

Natural gas distributors

For rate regulated natural gas distributors, short-term debt is used for an unfunded portion to true-up the deemed capitalization to the utility's actual capitalization. As the variance between actual and deemed capital structures is generally small, the unfunded portion is typically a small fraction of total capitalization for rate-setting purposes.

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[69] The PC Bond data was, prior to mid-2007, produced by Scotia Capital Inc., and publicly available from Statistics Canada and the Bank of Canada.
[70] Written Comments of the London Property Management Association and the Building Managers and Owners Association of the Greater Toronto Area. October 30, 2009, p. 32

In a Cost of Service application, the applicant natural gas distributor forecasts the cost of short-term debt for the test year, and this is subject to review. The Board notes that no participant questioned the Board's policy and practice for natural gas distributors, and **has determined that it is appropriate to continue with this approach.** With the development of a new deemed short-term debt rate for use in the electricity transmission and distribution sector, the Board notes that it and other participants may take into consideration the deemed short-term debt rate, as discussed below and documented in Appendix D.

OPG's prescribed rate-regulated baseload generation

Consistent with the Board's practice in OPG's 2008 Cost of Service application (EB-2007-0905), **the Board is of the view that OPG's cost of short-term debt should be set in a manner similar to that adopted for natural gas distributors.**

Electricity transmitters and distributors

Prior to the issuance of 2008 rates, short-term debt was not factored into electricity distribution and transmission rate-setting. In the December 20, 2006 Report, the Board adopted a deemed short-term debt rate that would apply to a deemed 4% of the capital structure. The formula for the deemed short-term debt rate was established as the average 3-month Bankers' Acceptance rate plus a 25 basis point spread, determined three months in advance of the effective date for rates. The short-term debt rate, and deemed 4% component of the capital structure was introduced in Cost of Service applications for 2008 distribution rates.

In the consultation, certain electricity distributors commented that they are unable to borrow at rates as predicted by the current deemed short-term debt formula. [71,72] These electricity

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[71] Written Comments of FortisOntario Inc. September 10, 2009. p. 8, bullet at bottom of page. FortisOntario Inc. indicates that a high-grade utility would be Bankers' Acceptance + 175 basis points, for smaller operating company entities, it would be Bankers' Acceptance + 250-275 basis points

distributors have documented that the cost of short-term debt is much higher and depends on market conditions and on the rating of a distributor. The concern was not with using the Bankers' Acceptance rate, but primarily with the spread over Bankers' Acceptances. The suggestion was that the Board should obtain estimates of the spread from major Canadian banks, and add this to the average Bankers' Acceptance rate as calculated for rate-setting. To lessen the burden, it was suggested that this spread be calculated annually in January of the year, and used as needed. The Board could obtain quotes from banks more frequently if market conditions warranted it.

The Board is of the view that this approach to establishing the deemed short-term debt rate has merit. **The Board thus will adopt the following approach to determining the deemed short-term debt rate:**

- In mid-January of each year, the Board will contact major Canadian banks to obtain estimates of the spread of a typical short-term loan for an R1-low utility over the 3-month Bankers' Acceptance rate. The selection of R1-low is to reflect the fact that most distributors currently going to market would fall in that category; only Toronto Hydro Electric Systems Limited and Hydro One Networks Inc. would be R1-Mid or R1-High. Up to six quotes will be obtained. Ideally, the high and low estimates will be discarded to reduce the influence of outliers, and the average spread will be calculated. In the event that less than four quotes are obtained, the average spread will be calculated without discarding high and low estimates. The identity of the banks providing quotes will be protected.

- For the month three months in advance of the effective date for rates, the average 3-month Bankers' Acceptance rate should be calculated based on data for all business days in the month. To this will be added the average spread calculated above, giving the deemed short-term debt rate for rate-setting purposes.

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[72] Ontario Energy Board. Transcript of Consultation Process on Cost of Capital Review. October 6, 2009, p.144, l. 20 to p. 146, l. 22. Also, p. 148, l. 19 to p. 149, l. 15.

Full documentation on the deemed short-term debt rate methodology is provided in Appendix D.

In its final comments, LPMA/BOMA submitted that the current formula should be retained, but the spread increased from 25 basis points to 50 basis points, on the basis of recent economic history.[73] The Board has determined that distributors and other participants provided sufficient documentation that the spread over bankers' acceptance rates with which they can borrow short-term debt is much higher than the 25 basis points currently used, or even the 50 basis points proposed by LPMA/BOMA. Further, LPMA/BOMA's proposal could possibly need review in the future. The Board is of the view that its adopted approach, while entailing some more work by the Board to obtain the spread quotes from the banks each year, is more flexible and will provide more reasonable estimates of the cost of short-term debt in each year.

[73] Written Comments of the London Property Management Association and the Building Managers and Owners Association of the Greater Toronto Area. October 30, 2009. p, 31.

4.5 Summary

The key elements of the Board's cost of capital policy are summarized in the following table.

Table 2: Components of the Board's Cost of Capital Policy

Capital structure	• 60% debt (56% long-term and 4% short-term) and 40% equity for electricity distributors. • Gas distributors, electricity transmitters and OPG will continue with approved capital structures.
Short-term debt rate	• Once a year, in January, obtain real market quotes from major banks, for issuing spreads over Bankers Acceptance rates for the cost of short-term debt. • The short term rate will be calculated as the average Bankers' Acceptance for the month 3 months in advance of the effective date for the rates, plus the spread for the year calculated above.
Long-term debt rate	• The deemed long-term debt rate will be based on the Long Canada Bond Forecast plus an average spread with an A-rated long-term utility bond yield). • Third-party embedded/actual debt with fixed rates, terms and maturity will get the actual rate. • Affiliate embedded/actual debt with fixed rates, terms and maturity will get the lower of actual and deemed debt rate at time of issuance. • Utility provides forecasts of new debt for a forward test year, where possible. New third-party debt will be accepted at the negotiated market rate. If a forecasted new rate is not available (i.e., due to timing), the deemed long-term debt rate may apply. • For new affiliated debt, the deemed long-term debt rate will be a ceiling on the allowed rate. The onus will be on the utility to demonstrate that the applied for rate and terms are prudent and comparable to a market-based agreement and rate on arms-length commercial terms. • Variable-rate debt will be treated like new affiliated debt. • Renegotiated or renewed debt will be considered new debt. • Where a utility has no actual debt, the deemed long-term debt rate shall apply.
Common equity return	• Refined formula-based ROE will be calculated as the base ROE + 0.5 X (change in Long Canada Bond Forecast from base year) + 0.5 X (change in the spread of (A-rated Utility Bond Yield – Long Canada Bond Yield) from the spread in the base year). This includes an implicit 50 basis points for transactional costs. • The ROE (and the short-term and long-term debt rates) will be based on data for the month 3 months in advance of the effective date for rates. • Reset formula for 2010: The base ROE in the refined formula will be calculated for 2010 as Long Canada Bond Forecast rate plus an ERP of 550 basis points, and reflects multiple, empirically supported, estimates provided in consultation which led to this report.

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5 Implementation

5.1 Transition to Recommended Cost of Capital

The policy set out in Chapter 4 of this report will come into effect for the setting of rates, beginning in 2010, by way of a cost of service application.

The Board's "Minimum Filing Requirements for Natural Gas Distribution Cost of Service Applications" and the Board's "Filing Requirements for Transmission and Distribution Applications" are sufficient for the purposes of implementing the policies set out in this report. Those requirements include information to be filed in support of a utility's proposed cost of capital in a cost of service application. There is no need for additional filing requirements. The onus is on an applicant to adequately support its proposed cost of capital, including the treatment of and appropriate rates for debt instruments. The Board notes that this is being done in cost of service applications. However, the Board wishes to point out the increased emphasis that it is placing on applicants to support their existing and forecasted debt, and the treatment of these in accordance with the guidelines, or to support any proposed different treatment.

5.1.1 Continued Migration to Common Capital Structure

The Board will continue to include an adjustment to rates in 2010, as applicable, as outlined in its December 20, 2006 Report, in order to transition electricity distributors to the single deemed capital structure of 60% debt and 40% equity.

With 2010 rates, most electricity distributors will have completed the transition to the deemed capital structure of 60% debt (56% long-term and 4% short-term) and 40% equity. However, some distributors have not completed the transition. The Board will deal with the transition to the common deemed capital structure for these distributors when they file applications for rates.

5.2 Impact on Other Board Policies

5.2.1 Prescribed Interest Rates

The deemed short-term debt rate and the prescribed interest rate for deferral and variance accounts use closely related methodologies. Distributors commented that changes to the deemed short-term debt rate should be reflected in the prescribed interest rate. Further, there was acknowledgement that any new formula for the prescribed interest rate for deferral and variance accounts, used to calculate carrying charges on balances, would apply to both credit and debit balances. The Board agrees. While the policy in this report does not cover the prescribed interest rates, the Board intends to initiate a review of its approach to calculating the prescribed interest rate to align it with the approaches set out in this report.

6 Annual Update Process and Periodic Review

6.1 Annual Update Process

The Board will apply the methods set out in this report annually to derive the values for the ROE and the deemed long-term and short-term debt rates for use in cost of service applications.

If the application of these methods produces numerical results that, in the view of the Board, raise doubt that the FRS is met, the Board may then use its discretion to begin a consultative process to determine whether circumstances warrant an adjustment to the formulaic approach, in general, or to any of the cost of capital parameter values specifically. The Board also may, at its discretion and based on the circumstances at the time, use the previous year's formula-generated values on an interim basis until its final determination is made following the consultative process.

Stakeholders proposed a variety of tests and approaches that could be used to supplement the Board's annual review of the cost of capital parameters. The Board is of the view that any tests or approaches used to assess the reasonableness of the cost of capital parameters should be consistent with the formulaic ROE adjustment mechanism adopted. Accordingly, the Board will not attempt to annually derive the ROE using CAPM, DCF or other cost of capital methodologies to assess the reasonableness of the formula-generated ROE. The Board notes that participants are free to perform such calculations and ask the Board to review the formula when they feel it is appropriate.

For the purposes of assessing the reasonableness of results on an annual basis, the Board will examine the values produced by the Board's cost of capital methodology, and the relationships between them, in the context of the economic and financial conditions of the day. Further and consistent with the 1997 Draft Guidelines, the Board will review its approach as conditions arise that may call into question its validity. Further, parties may ask the Board to review its cost of capital policies when they feel it is appropriate or the

Board may do so on its own initiative. In either case it will be the Board's decision as to the time for a review. Finally, the Board may request the presentation of other tests or require some weighting for other tests should the Board want to assure itself that its approach does not lead to perverse results and is directionally in line with other market indicators. [74]

6.2 Periodic Review

The Board has determined that it will periodically review its formulaic ROE adjustment mechanism. The use of any formulaic approach to approximate a change in the ROE is bound to be imperfect and any such imperfection may, over time, result in cumulative or compounding effects such that the application of it may not continue to meet the FRS.

The Board notes that the time period for a review suggested by stakeholders varied from 3-5 years, with Energy Probe suggesting that "4-5 years is probably too short."[75]
The Board has determined that a review period of five years provides an appropriate balance between the need to ensure that the formula-generated ROE continues to meet the FRS and the objective of maintaining regulatory efficiency and transparency. Accordingly, the Board intends to conduct its first regular review in 2014 and any changes to the policy made as a result of that review would apply to the setting of rates for the 2015 rate year.

At the time of the review, the Board will provide guidance to stakeholders through, for example, an issues list similar to that issued on July 30, 2009, and the relevant period over which to estimate the risk-free rate. This latter approach will promote the use of a common basis to derive cost of capital estimates, increasing their direct comparability.

The periodic review will not necessarily result in a resetting of the base ROE or refining of the adjustment factors and/or terms of the formula. The Board will seek the views of

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[74] Ontario Energy Board. Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Utilities. March 1997. p. 2.
[75] Written Comments of Energy Probe Research Foundation, September 8, 2009, p. 12.

stakeholders on the need to reset the ROE and the need to revise the formula. If the Board is satisfied that its approach remains appropriate, the base ROE and the formula will remain unchanged and the review will conclude.

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Appendix A: Summary on the Formula-Based Return on Equity Guidelines in Effect in the 2009 Rate Year

The Board's existing formula-based approach using the equity risk premium ("ERP") method for determining the fair rate of return for natural rate regulated natural gas utilities is set out in its 1997 *Draft Guidelines on a Formula-Based Return on Common Equity.* The 1997 *Draft Guidelines* were first applied in the EBRO 495 proceeding which set fiscal 1998 rates for the Consumers' Gas Company Ltd. The Board's December 2006 *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* reaffirmed the continued use of this approach for electricity distribution utilities subject to a number of minor modifications, as described below.

Draft Guidelines on a Formula-Based Return on Common Equity for Regulated Natural Gas Utilities:

The 1997 Draft Guidelines, have two phases: an initial setup and an ongoing adjustment mechanism.

<u>Initial Set-Up</u>

Step 1: Establish the forecast of the long Government of Canada yield for the test year

The forecast yield of long-term Government of Canada bonds is established for the test year by taking the average of the 3 and 12 months forward 10-year Government of Canada bond yield forecasts, as stated in the most recent issue of Consensus Forecasts, and adding the average of the actual observed spreads between 10 and 30-year Government of Canada bond yields, for each business day in the month corresponding to the most recent Consensus Forecast issue.

Step 2: Establish implied risk premium

A utility's test year ROE will consist of the projected yield for 30-year long Canada bonds plus an appropriate premium to account for the utility's risk relative to long Canada bonds. The primary methodological approach to be used in evaluating the appropriate risk premium should be the ERP test.

The ERP test is designed to measure the cost of equity capital from the capital attraction perspective. It relies on the assumption that common equity is riskier than debt and that investors will demand a higher return on shares, relative to the return required on bonds, to compensate for that risk. The premium required by an investor to assume the additional risk associated with an equity investment is taken to be the difference between the relevant debt rate, usually the yield on long-term government bonds, and some estimate of the stock's cost of equity. The recommended cost of equity value under the ROE approach is therefore usually computed as the sum of the test-period forecast for the government yield and the utility-specific risk premium the analyst has estimated based on historical ROE evidence and forward-looking considerations.

The Adjustment Mechanism

Once the initial ROE has been set for each of the utilities, a procedure must be put in place to automatically adjust the allowed ROE for each utility to account for changes in long Canada yield expectations. The timing of the adjustment mechanism process for each utility will be consistent with its fiscal year-end.

Step 1: Establish the forecast long Canada rates

The formula-based ERP approach annually adjusts a utility's allowed ROE based on changes in forecast long-term Government of Canada bond yields. Each year the process outlined in Step 1 of the initial setup phase will be repeated and an updated, consensus-based forecast of 30-year long-Canada bond yields will be obtained. The current test year rate forecast will then be compared to the previous test year forecast.

Step 2: Apply adjustment factor

The difference between the forecast long Canada rate calculated in Step 1 and the corresponding rate for the immediately preceding year should be multiplied by a factor of 0.75 to determine the adjustment to the allowed ROE. This adjustment will then be added to the utility's previous test year ROE and the sum should be rounded to two decimal points.

Term of the Rate of Return Formula

The rate of return formula should be reviewed as conditions arise that may call into question its validity. Parties may ask the Board to review the formula when they feel it is appropriate or the Board may do so on its own initiative. In either case it is the Board's decision as to the time for a review.

The Board may request the presentation of other tests or require some weighting for other tests in the formula should the Board want to assure itself that the ERP formula approach does not lead to perverse results and is directionally in line with other market indicators.

December 20, 2006 *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors*:

Since 1999, the cost of capital for electricity distributors has been governed by the Board's Decision with Reasons in proceeding RP-1999-0034. This decision established a size-related capital structure for distributors and set the return on equity at 9.88%.[76] In the December 20, 2006 Report, the Board determined that the current approach to setting ROE would be maintained. The ROE will continue to be determined based on the Long Canada

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[76] Ontario Energy Board. Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors. December 20, 2009. p. 3.

Bond Forecast plus an ERP. The approach is a modified Capital Asset Pricing Model method and includes an implicit 50 basis points for transaction costs. At that time, the Board also adopted deemed equity of 40% for all distribution utilities.

In the December 20, 2006 Report, the Board clarified the starting point to be used for each annual update and determined that it is appropriate to use the ROE calculated at that time as the starting point. This figure was 9.35%, as per the Board's determination in Hydro One Network Inc.'s RP-1998-0001 Decision. The Board indicated that it will use 9.35% as the starting point for the update. As a result of the December 20, 2006 Report, the ROE for any period would be:

$ROE_t = 9.35\% = 0.75 \times (LCBF_t – 5.50\%)$

Where:

- The ROE is set three months in advance of the effective date for the rate change. Therefore, for May 1 rate changes the ROE will be based on January data.

- The Long Canada Bond Forecast ($LCBF_t$) for any Period is the average of the 3-month and 12-month forecasts of the 10-year Government of Canada bond yield as published in Consensus *Forecasts* at time t *plus* the average of the actual observed spreads between 10 and 30-year Government of Canada bond yields, for each business day during the month corresponding to the *Consensus Forecasts* at time t.

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Appendix B: Method to Update ROE

With the release of this report, the Board is resetting and refining its formulaic approach for determining a utility's Return on Equity ("ROE") applicable to the prospective test year. The formula has been reset to address the difference between the allowed ROE arising from the application of the formula and the rate of ROE for a low risk proxy group that cannot be reconciled based on differences in risk alone. The formula has been refined to reduce the sensitivity of the approach to changes in government bond yields due to monetary and fiscal conditions that do not reflect changes in utility cost of equity.

The formula as set out in this report includes (a) a term to reflect the change in the Long Canada Bond forecast ("LCBF") and (b) a term to reflect the change in the spread between A-rated Utility bond yields over the Long Canada Bond yield.

The adjustment factor for the LCBF term is set at 0.5. The adjustment factor for the A-rated Utility bond term is set at 0.5. The methodology for calculating the Long Canada Bond forecast is the same as that set out in the Board's December 20, 2006 Report.

The base for the ROE adjustment formula is set at 9.75%. The corresponding base LCBF is 4.25% and the spread in 30-year A-rated Canadian utility bonds over the 30-year benchmark Government of Canada bond yield is 1.415%.

While there is a change in the base numbers and the adjustment formula, the general approach for calculating the updated ROE is the same as that set out in the Board's December 20, 2006 Report.

The ROE for the prospective test year (ROE_t) will be calculated by the following adjustment formula:

$$ROE_t = BaseROE + 0.5 \times (LCBF_t - BaseLCBF) + 0.5 \times (UtilBondSpread_t - BaseUtilBondSpread)$$

Where:

- $LCBF_t$ is the Long Canada Bond Forecast for the test year, and is calculated as:

$$LCBF_t = \left[\frac{{}_{10}CBF_{3,t} + {}_{10}CBF_{12,t}}{2} \right] + \left[\frac{\sum_i ({}_{30}CB_{i,t} - {}_{10}CB_{i,t})}{I} \right]$$

  Where

  - $_{10}CBF_{3,t}$ is the 3-month forecast of the 10-year Government of Canada bond yield as published in Consensus Forecasts three (3) months in advance of the implementation date for rates;

- $_{10}CBF_{12,t}$ is the 12-month forecast of the 10-year Government of Canada bond yield as published in Consensus Forecasts three (3) months in advance of the implementation date for rates;
- $_{30}CB_{i,t}$ is the benchmark bond yield rate for the 30-year Government of Canada bond at the close of day i of the month that is three (3) months in advance of the implementation date for rates, as published by the Bank of Canada [**Cansim Series V39056**];
- $_{10}CB_{i,t}$ is the benchmark bond yield rate for the 10-year Government of Canada bond at the close of day i of the month that is three (3) months in advance of the implementation date for rates, as published by the Bank of Canada [**Cansim Series V39055**]; and
- I is the number of business days for which Government of Canada and A-rated Utility bond yield rates are published in the month three (3) months in advance of the implementation date for rates.

- $UtilBondSpread_t$ is the average spread of 30-year A-rated Canadian Utility bond yields over 30-year Government of Canada bond yields over all business days in the month three (3) months in advance of the implementation date for rates, and is calculated as

$$UtilBondSpread_t = \frac{\sum_i ({}_{30}UtilBonds_{i,t} - {}_{30}CB_{i,t})}{I}$$

Where:

- $_{30}UtilBonds_{i,t}$ is the average 30-year A-Rated Canadian Utility bond yield rate, from Bloomberg L.P., for business day i of the month that is three (3) months in advance of the implementation date for rates [**Series C29530Y**];
- $_{30}CB_{i,t}$ is the benchmark bond yield rate for the 30-year Government of Canada bond at the close of day i of the month that is three (3) months in advance of the implementation date for rates, as published by the Bank of Canada [**Cansim Series V39056**]; and
- I is the number of business days for which Government of Canada and A-rated Utility bond yield rates are published in the month three (3) months in advance of the implementation date for rates.

As noted above, based on September 2009 data, the base ROE is set at 9.75% and the corresponding *BaseLCBF* is 4.25% and *BaseUtilBondSpread* is 1.415%. Thus the ROE adjustment formula is specified as:

$$ROE_t = 9.75\% + 0.5 \times (LCBF_t - 4.25\%) + 0.5 \times (UtilBondSpread_t - 1.415\%)$$

The ROE for any period will be rounded and expressed as a percentage with two decimal places (i.e., XX.XX%).

As for other cost of capital parameters, data will be for the month that is three months prior to the effective date for the new rates. For example, for rates effective May 1, January data will be used to calculate the updated ROE. This means is that *Consensus Forecasts* published in the month of January, and Bank of Canada and Bloomberg L.P. data for all business days during the month of January will be used to calculate the updated ROE.

The necessary data are available shortly after the end of the month, and thus poses no undue delays for rate-setting.

The use of the ROE will be in accordance with the policy described in section 4.2 of this report.

Appendix C: Method to Update the Deemed Long-term Debt Rate

The Board will use the Long Canada Bond Forecast plus an average spread of A-rated Corporate Utility bond yields over the actual Long Canada Bond yield to determine the updated deemed long-term ("LT") debt rate.

This approach is consistent with the methodology adopted in the December 20, 2006 Report, to represent a fair market rate for a long-term debt instrument in the test period. The only change is the source of the corporate bond yields, which is now the A-rated Corporate Utility bond index yield obtainable from Bloomberg L.P.

Consistent with the approach used in prior guidelines, the *2006 Electricity Distribution Rate Handbook* and the December 20, 2006 Report, the ROE and the deemed long-term debt rates are based on the same forecast of the risk-free rate. For certainty, the Long Canada Bond Forecast ($LCBF_t$) used in the ROE formula will be used in the calculation of the deemed LT rate.

The deemed LT debt rate ($LTDR_t$) will be calculated as follows:

$$LTDR_t = LCBF_t + \frac{\sum_i ({}_{30}UtilBonds_{i,t} - {}_{30}CB_{i,t})}{I}$$

Where:

- $LCBF_t$ is the Long Canada Bond Forecast for the prospective test year, as defined in Appendix B for the calculation of the ROE;
- ${}_{30}UtilBonds_{i,t}$ is the average 30-year A-Rated Canadian Utility bond yield rate, from Bloomberg L.P., for business day *i* of the month that is three (3) months in advance of the implementation date for rates **[Series C29530Y]**;
- ${}_{30}CB_{i,t}$ is the benchmark bond yield rate for the 30-year Government of Canada bond at the close of day *i* of the month that is three (3) months in advance of the implementation date for rates, as published by the Bank of Canada **[Cansim Series V39056]**; and
- I is the number of business days for which Government of Canada and A-rated Utility bond yield rates are published in the month three (3) months in advance of the implementation date for rates.

As for other cost of capital parameters, data will be for the month that is three months prior to the effective date for the new rates. For example, for rates effective May 1, January data will be used to calculate the updated deemed LT debt rate.

The use of the deemed LT debt rate will be in accordance with the policy described in section 4.4.1 of this report and based on the evidentiary record in the particular application.

Appendix D: Method to Update the Deemed Short-term Debt Rate

The Board will use a new methodology to estimate the deemed short-term ("ST") debt rate, consisting of the average 3-month Bankers' Acceptance rate as published by the Bank of Canada plus a forecasted average spread of short-term debt issuances over 3-month Bankers' Acceptance rates for R1-low Canadian utilities.

This is a change over the previous methodology, specifically in the spread above the Bankers' Acceptance rate which previously was fixed at 25 basis points. The new methodology will use spread forecasts obtained from Canadian prime banks to better reflect the short-term rates that utilities can obtain short-term financing for.

The calculation of the deemed ST debt rate will be done through a two-step process.

1. Annual calculation of the average spread over 3-month Bankers' Acceptance Rates

Once a year, in January, the average spread of short-term debt issuances over 3-month Bankers' Acceptance rates will be obtained by Board staff contacting major Canadian banks. Up to six quotes will be obtained to calculate the average spread to be used during the calendar year. Ideally, the high and low estimates will be discarded to reduce the influence of outliers, and the average spread will be calculated. In the event that less than four quotes are obtained, the average spread will be calculated without discarding high and low estimates.

If market conditions materially change, the Board could decide that the average spread may need to be updated at some point other than January.

2. Calculation of the Deemed Short-Term Debt Rate

The deemed short-term debt rate ($STDR_t$) for the prospective test year will be calculated as:

$$STDR_t = \frac{\sum_i BA_i}{I} + AnnSpread_t$$

Where:

- BA_i is the 3-month Bankers' Acceptance Rate for day i in the selected month, as published by Statistics Canada and the Bank of Canada [**Cansim Series V39071**];

- I is the number of business days for which published Government of Canada and A-rated Utility bond yield rates are published in the month three (3) months in advance of the implementation date for rates; and
- $AnnSpread_t$ is the average annual spread in short-term debt issuances for an R1-low utility over 3-month Bankers' Acceptance rates for the test year t, calculated in step 1 above.

As for other cost of capital parameters, data will be for the month that is three months prior to the effective date for the new rates. For example, for rates effective May 1, January data will be used to calculate the updated deemed ST debt rate.

The use of the deemed ST debt rate will be in accordance with the policy described in section 4.4.2 of this report.

Ontario Energy Board **Commission de l'énergie de l'Ontario**

EB-2010-0002

IN THE MATTER OF AN APPLICATION BY

HYDRO ONE NETWORKS INC.

2011 and 2012 TRANSMISSION REVENUE REQUIREMENT AND RATES

DECISION WITH REASONS

December 23, 2010

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EB-2010-0002

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Hydro One Networks Inc. for an order or orders approving a transmission revenue requirement and rates and other charges for the transmission of electricity for 2011 and 2012.

BEFORE: Paul Sommerville
Presiding Member

Ken Quesnelle
Member

Paula Conboy
Member

DECISION WITH REASONS

DECEMBER 23, 2010

BACKGROUND

On May 19, 2010 Hydro One Networks Inc. (Hydro One, the Applicant, or the Company) filed an application for 2011 and 2012 transmission revenue requirement and rates. The revenue requirement and charge determinants approved for Hydro One in this proceeding would be combined with other licensed Ontario transmitters to determine the Uniform Transmission Rates (UTRs) for 2011 and 2012. The Board assigned file number EB-2010-0002 to the application and issued an approved issues list on July 20, 2010.

Hydro One Networks Inc. is the largest electricity transmitter in Ontario with approximately 29,000 circuit kilometers of transmission line, 247 transformer stations and 33 switching stations. The network connects 91 generating stations, 51 Local Distribution Companies (LDC's) and 65 end-use transmission customers (89 connection points).

Hydro One sought approval of a transmission revenue requirement of $1,446 million for 2011 and $1,547 million for 2012, and approval of changes to the provincial UTRs that are charged for electricity transmission, to be effective January 1, 2011 and January 1, 2012.

The Board issued Procedural Order No.1 on June 28, 2010, establishing the procedural schedule for a number of early events and included a draft issues list.

The timing of the filing of the application was influenced by the receipt by the Company of a letter from the Minister of Energy, the sole shareholder of the Company on May 5, 2010. The Company's original proposal was held back in order to allow the Company to accommodate the Minister's instructions to re-focus the Company's proposals in the application to only those spending proposals necessary to ensure the safe and reliable operation of the system, and the implementation of capital programs specifically identified by the Ontario Power Authority as required immediately. The Company reviewed its application in light of the Minister's instruction and made consequential changes. The extent and adequacy of those changes was a matter of dispute among the parties in this case.

Intervenors

The following intervenors took an active role in this proceeding: Vulnerable Energy Consumers Coalition (VECC), Building Owners and Managers Association of the Greater Toronto Area and the London Property Management Association (BOMA/LPMA), School Energy Coalition (SEC), Canadian Manufacturers and Exporters (CME), Consumers Council of Canada (CCC), Energy Probe Research Foundation (Energy Probe), Association of Major Power Consumers in Ontario (AMPCO), Power Workers Union (PWU), Ontario Power Authority (OPA), Independent Electricity System

Operator (IESO), Association of Power Producers of Ontario (APPrO), Bruce Power, HQ Energy Marketing Inc., Pollution Probe and Toronto Hydro-Electric System Limited (THESL). A full list of all 27 intervenors in this case is attached in Appendix "A".

Hydro One Motion

Hydro One brought a motion before the Board on June 16, 2010 requesting an order severing the issue of the AMPCO proposal to alter the method of determining the transmission network charge, termed the "High 5 Proposal" (Issue 8.1), for review and assessment in a separate generic proceeding. The Board heard this motion on July 20, 2010 and denied the motion in an oral decision delivered on that day. The Board also issued its decision on the draft issues list in the same oral decision. That approved issues list was attached to Procedural Order No. 2, issued on July 21, 2010.

A copy of the decision on the motion is attached as Appendix B and the approved Issues List is attached as Appendix C.

Canadian Manufacturers and Exporters Motion

CME brought a motion before the Board on the first day of the oral hearing, September 20, 2010, requesting an order requiring Hydro One to produce certain materials provided to the Hydro One Board of Directors and requested in CME Interrogatories 1 and 2. The Board granted the motion in an oral decision on September 20, 2010.

A copy of the decision on the CME motion is attached as Appendix D.

Intervenor Evidence

Two intervenors filed evidence before the Board: AMPCO provided evidence on the High 5 charge determinant issue (Exhibit M-1), and CME provided evidence on Total Ontario Electricity Bill Impacts (Exhibit N-1).

Settlement Conference

A settlement conference for this proceeding was held on September 16, 2010, however no settlement was achieved.

The Hearing, Submissions and Evidence

The oral hearing for this proceeding took place in September and October 2010, concluding with Hydro One's oral argument-in-chief on October 7, 2010.

Board staff and intervenor submissions were filed on October 22, 2010 and November 2, 2010 respectively. The IESO filed its submissions on October 15, 2010. Hydro One submitted its reply argument on November 12, 2010.

Copies of the evidence, exhibits, submissions and transcripts of the proceeding are available for review at the Board's offices or on the Board website, www.oeb.gov.on.ca.

Further procedural details are found in Appendix A.

Confidentiality

During the proceeding, confidential treatment was requested for a number of documents. These documents are filed at the Board's offices.

The Board considered the full record of the proceeding but has summarized the record only to the extent necessary to provide context to its findings.

LOAD FORECAST

Hydro One's transmission load forecast for the 2011 and 2012 test years, including the impact of Conservation and Demand Management (CDM), is shown in the table below:

Transmission Load Forecast, 2011 and 2012
(12 Month Average Peak MW)

		Rate Categories		
	Demand	**Network Connection**	**Line Connection**	**Transformation Connection**
2011	20,613	20,150	19,500	16,850
2012	20,292	19,485	19,286	16,667

Source: Exhibit A/Tab12/Schedule 3

CDM, increased embedded generation and slower economic growth coming out of the recent economic downturn are the major influences on the 2011 forecast resulting in a 1.3 percent decrease 2010. For 2012, load is forecast to decrease by a further 1.6 percent.

The load forecast as presented in the pre-filed evidence was largely accepted without comment by Board staff and intervenors. Concern was raised by SEC and BOMA/LPMA respecting the apparently outdated information that was used in overall business planning and to develop the load forecast. For example, some of the forecasts date from November and December 2008.

The major load forecast issue raised in argument was the issue of the adjustment of the load forecast for CDM. This was primarily raised by VECC, supported by CCC.

VECC indicated that the Board, in its EB-2008-0272 decision, had found that it was appropriate for Hydro One to base its CDM adjustment on OPA information and analysis. In conformity with this direction Hydro One had used OPA information, but only information based on the OPA's CDM forecasts made as part of the Integrated Power System Plan (IPSP) proceeding (EB-2007-0707), which was suspended in 2008 as the result of a ministerial directive. VECC indicated that Hydro One had not used information recently released by the OPA as part of the CDM Targets consultation (EB-2010-0218) and revealed in a current Hydro Ottawa rates case (EB-2010-0133). VECC maintained that this new information showed that CDM savings are less than half of that reflected in the original IPSP documentation.

Accordingly, VECC submitted that it would be reasonable to assume a cumulative CDM impact for 2011 of no more than 1868 MW, as opposed to the 2486 MW assumed by Hydro One. For 2012, it would be reasonable to assume a cumulative CDM impact of no more than 2377 MW, as opposed to the 3064 MW assumed by Hydro One.

VECC also noted that Hydro One was unable to provide any details as to how the peak MW savings attributed to each type of CDM program was translated into average monthly MW savings (as this information was not provided by the OPA). VECC submitted that Hydro One has the responsibility to obtain sufficient supporting details so it can satisfy both itself and other participants in these proceedings that CDM has been properly incorporated into its load forecast.

CCC supported the VECC submissions, indicating that it is critical for Hydro One to use the best available information regarding the impact of CDM programs in the development of its load forecast.

In its reply argument, Hydro One submitted that VECC's argument relied on the CDM energy impact from the OPA, not the corresponding CDM peak impact, which is the appropriate comparison to the CDM values used by Hydro One in its load forecast.

It is Hydro One's position that the OPA's CDM peak impact found in the Hydro Ottawa evidence demonstrates that the CDM peak impact Hydro One used in the load forecast is consistent with the latest information from the OPA.

Consequently, Hydro One submitted that CDM impacts have been appropriately reflected in its load forecast.

Board Findings

The Board notes that the only issue raised regarding the load forecast proposal concerns CDM impact over the relevant time frame. This is not the first time that accounting for the effects of CDM has proven to be elusive. The Board has recently directed Hydro One Distribution to provide information to the Board and the intervenors respecting the accuracy of its assumptions regarding CDM effects (EB-2009-0096). It is clear from Hydro One's evidence in this case that the OPA estimates of impacts are still rooted in the evidence filed in support of the IPSP in 2007. This evidence should be updated to reflect the most current estimates.

It appears that the OPA has provided some revisions to adjust the assumed CDM impacts as reflected in the evidence filed in a recent Hydro Ottawa rates case (EB-2010-0133), but those revisions were not tested in that case, given that the case was dismissed, nor was the rationale for the revised assumptions detailed. The revisions reflected in the Hydro Ottawa case are quite substantial, and if implemented in this case would result in a significant reduction in anticipated CDM effects. But there does not appear to be an evidentiary basis in this case that would allow the Board to adopt them.

Over the last number of years utilities across the province, including Hydro One Distribution, have spent very considerable sums of ratepayer or taxpayer money in pursuit of the Government's conservation and demand management goals. Recently, the government has intensified this activity through the establishment of specific CDM targets on a distributor by distributor basis. While each distributor has its own specific target for CDM reductions, these specific goals are derived by allocating a global target to the individual distributors. While the budgeting process for distributors to pursue these CDM goals is not finalized, it is clear that very substantial amounts of money will be required to achieve the targets established by the Government.

The Board is concerned that in this environment of increased pressure to pursue CDM, attended as it is with corresponding costs, that there does not appear to be a broadly accepted methodology in place to identify the reasonably anticipated effects of any CDM program on the throughput of the respective distribution or transmission systems.

Estimates and forecasts were an inevitable feature of the early stages of an increased interest in conservation and demand management performance in the province. But we are now at a stage where the stakes are higher, the amounts of money necessary to meet targets has increased, and yet our ability to measure this activity is unacceptably primitive. The Board notes that there is an intention to develop more capable methods of assessing the actual impacts of CDM programs, which will be of direct relevance to load forecasting, and in developing an appropriate context in which to assess the cost-effectiveness of specific measures undertaken in this area of activity. The Board recognizes that the OPA is engaged in refining its abilities to evaluate, measure, and verify the CDM programs it intends to offer to LDCs pursuant to the government's latest directives. For the purposes of establishing credible load forecasts, much more acuity than is currently available is needed.

In the circumstances of this application, the Board is prepared to accept Hydro One's CDM estimates for the purposes of its load forecast. The Board recognizes that load forecasting is subject to a number of uncertainties, and attempting to account for the effects of CDM adds another layer of uncertainty. It is unpredictable whether these various uncertainties will act cumulatively or in opposition to each other in their effect on throughput. As a result, the Board accepts Hydro One's forecast, as the evidentiary record in this case does not offer a more certain number.

However, the Board considers it advisable to ensure that steps are taken to improve the assessment of CDM effects going forward, so that subsequent load forecasts can be better informed and predicated on substantiated empirical data.

Accordingly, the Board directs Hydro One to work with the OPA in devising a robust, effective and accurate means of measuring the expected impacts of CDM programs promulgated by the OPA. It is important that the terms of reference for the development of this methodology should, to the extent possible, be devised with input from and consultation with a sufficiently broad range of stakeholders so as to ensure that the resulting product has credibility within the sector. The Board requires that this work be performed within a timeframe so that its results will inform the Company's next rate application. Of course, if the development of the methodology results in interim learnings, it is expected that they will be shared broadly. The Board notes that there may be CDM programs that are additional to those promulgated by the OPA, but it is reasonable to assume that they will not form a large part of the overall CDM picture, and that those programs will also benefit from the analytical approach which emerges from the effort.

OPERATIONS, MAINTENANCE AND ADMINISTRATION EXPENSE

Hydro One Transmission's OM&A budget is grouped into different investment categories: Sustaining, Development, Operations, Customer Care, Shared Services and Taxes Other than Income Taxes. The table below sets out Hydro One's historic, bridge and test years OM&A expenses. The 2011 increase over the 2010 level approved ($426.2 million) in the last Hydro One Transmission proceeding (EB-2008-0272), is 2.4%.

Transmission OM&A Expenditures 2009 – 2012
($ million, including % variance from prior year)

	Historic			Bridge	Test	
Category	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Sustaining	**205.9**	**187.5**	**213.5** *13.9%*	**224.4** *5.1%*	**233.0** *3.8%*	**243.1** *4.3%*
Development	**8.4**	**9.2**	**14.0** *52.2%*	**19.0** *35.7%*	**18.2** *-4.2%*	**18.9** *3.8%*
Operations	**54.0**	**51.7**	**52.6** *1.7%*	**62.1** *18.1%*	**66.3** *6.8%*	**68.2** *2.9%*
Customer Care	**1.2**	**1.3**	**0.9** *-30.8%*	**1.1** *22.2%*	**1.1** *0.0%*	**1.2** *9.1%*
Shared Services & Other	**80.9**	**59.4**	**70.8** *19.2%*	**58.6** *-17.2%*	**46.9** *-20.0%*	**46.4** *-1.1%*
Tax other than Income Tax	**62.4**	**64.8**	**65.2** *0.6%*	**69.4** *6.4%*	**70.8** *2.0%*	**72.2** *2.0%*
Total	**412.9**	**373.8**	**417.0** *11.5%*	**434.6** *4.2%*	**436.3** *0.4%*	**450.0** *3.1%*

Source: Exhibit C1/Tab2/Schedule 1

The expenses presented in the table do not include proposed OM&A Development spending of $132.7 million to be captured in a deferral account for 2010, 2011 and 2012 for the 16 specific Green Energy Development projects in the "IPSP and Other Preliminary Planning Costs Deferral Account".

OVERALL OM&A

OM&A expenses are projected to increase by 0.4% in test year 2011 over the 2010 bridge year and by a further 3.1% in 2012. Hydro One stated that the test year expenditures are largely required to address the increasing maintenance requirements of an aging and expanding transmission system. Hydro One stated that increased spending is also required for the initiation of Smart Zone development work. The increases sought are partially offset by decreases to Development costs and increased Cornerstone savings within the Shared Services category.

Hydro One indicated that it had made reductions of $19.4 million in OM&A costs in response to the Minister's letter of May 5, 2010 from what was the originally planned proposal for 2011. These OM&A reductions consisted of a $12.9 million reduction in Sustaining OM&A and a reduction of $6.5 million in Shared Services and Other Costs. In addition, for 2012, related reductions were a $11.3 million decrease in Sustaining and an $8.6 million decrease in Shared Services & Other Costs, for a total 2012 OM&A reduction of $19.9 million. No reductions from the Company's original proposal were made in the Development and Operations OM&A budgets for either test year.

SEC argued that the overall level of OM&A spending proposed by Hydro One is too high. In its argument, SEC initially focused on what it referred to as Hydro One's controllable costs; that is: Sustainment, Development, Operations and Customer Care. These areas showed a cumulative increase of $81.8 million over 4 years or 32.8%.

SEC stated that of the $81.8 million increase, $49 million was already approved by the Board in its EB-2008-0272 decision; an increase of 19.6%. SEC submitted that the additional increase, a further 13.2% or $32.8 million over two years, is not reasonable, given the size of the increase approved by the Board in its previous decision.

SEC submitted that in view of the expanded capital expenditure plan, and the shifting of costs from OM&A to capital, it is appropriate for the Board to freeze spending levels and approve an OM&A budget for Sustaining, Development, Operations and Customer Care of $298.6 million for each of 2011 and 2012. This would reduce the revenue requirement for 2011 and 1012 by $20.0 million and $32.8 million respectively.

Board staff noted that the proposed OM&A budget is still $34.5 million above the Hydro One defined "minimum" requirements for 2011 and $37 million above "minimum" requirements for 2012. These defined minimum requirements form an integral part of Hydro One's planning process. In that process the Company has established a "minimum" spending level for numerous categories of project spending. The minimum levels represent a level of spending capable of avoiding major implications for the reliability and safety of the system for a defined period of time.

Board staff submitted that although Hydro One has made reductions to OM&A for the test years between its originally proposed levels to the current request, the evidence suggests that further reductions in OM&A spending could be made particularly in the areas of Development and Operations Costs (excluding compensation), Compensation Costs and Pension Costs. Board staff also noted that a number of cost effectiveness measures were discussed in the hearing, and these showed that Hydro One could improve cost performance. In summary, staff suggested that an additional 2-3% could be reduced from OM&A costs in addition to compensation related reductions. These submissions were supported by several intervenors.

VECC also noted that there were no reductions to the Operations and Development OM&A budgets and agreed with Board staff in saying that the overall OM&A levels were well above the 'minimum' levels. Regarding performance measures, VECC also submitted that Hydro One is not demonstrating improved productivity performance. VECC submitted that the Board should reduce the OM&A envelopes closer to minimum levels for the test years.

Intervenors also made comments on specific increases in categories of costs sought in the application.

Board Findings

While the Board notes that Hydro One is seeking a less significant increase in its OM&A as compared to previous years and applications, the Board finds that there is still room for further cost reductions to be made.

The Board is mindful that in previous decisions fairly significant increases have been approved by the Board. Those increases were considered by the respective panels of the Board hearing those cases, in light of the circumstances and evidence before them. Previously awarded increases do not in and of themselves support reductions in this case. This case must be considered in light of its particular circumstances and the evidence before the Board. The Board does not accept SEC's proposal to freeze spending in areas Sustaining, Development, Operations and Customer Care on the basis of the magnitude of increases approved in previous applications.

In recent decisions the Board has approved a gross amount, commonly referred to as the "envelope" to support the Company's OM&A activities. In this way, the Board provides the Company with the funding it believes has been supported by the evidence, without specifically directing the Company as to how the funds should be allocated among the various categories of OM&A spending. It is the Board's view that within the envelope the Company is far better able to make those kinds of allocations than the Board. The Board's envelope approach is also appropriate in this case because it appeared there was an apparent lack of sufficient evidence in several areas that would make it difficult for the Board to quantify disallowances in specific categories of spending.

There are exceptions. For example, in this proceeding the Board will make a specific finding with respect to Compensation. Otherwise the Board's commentary on the various categories of spending should be regarded as strongly influential to the Company as it makes it spending decisions, but not directive.

In this case the Board's concern about the proposed spending level relates directly to the Company's ongoing issues with productivity. The Mercer (Canada) Limited and Oliver Wyman Study ("Mercer Study") filed in the last transmission rates proceeding

(EB-2008-0272) , which is still the only empirical evidence respecting productivity before the Board, indicates that the Company is lagging behind its peers with respect to its productivity. Specifically, the Mercer study indicates that the Company is 17% above the median of its comparators. It is the Board's view that the spending level approved within the envelope must reflect the Board's concern about this issue. Some aspect of this issue can be addressed directly within the Compensation category of spending. But in other areas as well, the Board is determined to ensure that the Company improves its overall performance.

Accordingly, the Board will reduce the Company's OM&A envelope by 3% for 2011 and 4% for 2012 from applied-for levels. These reductions are to include the impact of the reductions in compensation as noted below and are to be calculated after the changes that the Board has ordered regarding HST impacts.

The Board notes that this will leave the overall OM&A levels substantially above the minimum levels, and the envelope approach reflects the absence of precision in the application as filed.

The Board also notes that the Company has also agreed to make adjustments to its PILs calculations related to Apprenticeship, Co-op Education and SR&ED Tax Credits, the Ontario Small Business Deductions and CCA changes. The Board concurs with these adjustments.

SUSTAINING

Sustaining OM&A consists of expenditures required to maintain transmission facilities at appropriate levels of reliability and service quality, and to satisfy legislative, regulatory, environmental and safety requirements. There are three categories within sustaining OM&A:

- Stations – which funds the work required to maintain assets within transmission stations including power transformers, circuit breakers and ancillary systems;
- Lines – which funds the work required to maintain 28,000 circuit kilometres of overhead transmission lines and 270 circuit kilometres of underground transmission lines; and
- Engineering and Environmental Support – which funds the work related to managing transmission assets including management of records and drawings, and services that provide technical expertise not available within Hydro One.

The historic, bridge and test year expenditures are summarized in the table below.

Sustaining OM&A ($ millions)

	Historic			Bridge	Test	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Stations	150.0	133.9	151.5	164.9	170.6	176.1
Lines	47.0	43.5	49.4	48.0	51.4	55.3
Engineering & Environmental Support	8.9	10.1	12.50	11.5	11.0	11.8
TOTAL	205.9	187.5	213.5	224.4	233.0	243.1

Source: Exhibit C1/Tab2/Schedule 3

In response to the Minister of Energy's letter of May 5, 2010 Hydro One reduced projected Sustaining OM&A expenditures by $12.9 million in 2011 and $11.3 million in 2012 over what was in the Company's original proposal for these test years.

Overall, Sustaining OM&A is still forecast to increase by 3.8% in 2011 over bridge year spending in 2010 and by a further 4.3% in 2012. Hydro One stated that the increased expenditures are required to meet the increased cost pressures as a result of new Environment Canada regulations for PCBs, new North American Electric Reliability Corporation regulatory requirements and aging assets that are increasing maintenance demands to maintain reliability and safety at current levels.

Energy Probe accepted Hydro One's evidence justifying these increased expenditures for Sustaining OM&A, recommending the Board approve the total Sustaining OM&A expenditures.

PWU submitted that it has reservations as to the adequacy of the proposed levels of Sustaining spending in the test years but found that Hydro One had struck a minimally acceptable balance between its ongoing operational needs and current rate impacts. The PWU indicated that a cut to Sustaining spending would exacerbate the "already dire state" of the Hydro One assets.

The PWU states that in recognizing the value of the reductions made by Hydro One in the area of Sustaining OM&A, the Board cannot limit its focus to the reduction in consumer rate impact but also has to be mindful of its statutory responsibilities that require it to assess any potential adverse impacts of reductions made to the work plan on Hydro One's ability to maintain and improve system reliability and quality of service. PWU goes on to suggest that reductions in Sustaining OM&A from the original proposal could contribute to a backlog of sustaining investment that would have to be undertaken in the future at a higher cost to future generations of consumers.

Board staff made no comments on the specific levels of OM&A expenditures for the Sustaining category.

In its argument over the proposed increases to controllable costs, SEC suggested that the Board freeze sustaining OM&A budgets at current levels.

The Board recognizes the importance to the Company of spending an appropriate amount on Sustaining OM&A to ensure that its transmission system is appropriately maintained and robust. The Board does not find it appropriate to direct Hydro One in its determination as to what is required in this area, provided there is sufficient evidence in any given case to support the Company's plans. The Board finds that Hydro One's overall approach to sustaining OM&A is reasonable.

DEVELOPMENT

Development OM&A provides funds for Research, Development and Demonstration ("RD&D") on emerging technologies, for standards development activity and for Smart Zone Development.

The historic, bridge and test year expenditures are summarized in the table below.

Development OM&A ($ millions)

	Historic			Bridge	Test	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Research Development & Demonstration	4.4	3.0	6.0	6.3	6.4	6.6
Standards Development	4.0	6.2	7.9	8.7	7.8	8.3
Smart Zone Development*				**4.0**	**4.0**	**4.0**
TOTAL	8.4	9.2	14.0	19.0	18.2	18.9
Development Work for Transmission Projects	0	0	1.9	8.2	35.7	46.7

Source: Exhibit C1/Tab2/Schedule 4
*New development initiative

The line in the table above entitled "Development Work for Transmission Projects" is that category of spending which is intended to be reflected in a proposed deferral account respecting Green Energy Programs.

CCC submitted that the RD&D budget was not supported with a project by project analysis. In addition, CCC argued that Hydro One did not provide a business case for Smart Grid Development. As a result of the insufficient evidence provided, CCC submitted that the Board should reduce the allowed Development budgets in these two areas by half; RD&D should be reduced to $3.2 million in 2011 and $3.3 million in 2012.

With respect to Smart Grid budgets, CCC concluded they should be reduced to $2.0 million in 2011 and $2.0 million in 2012.

Energy Probe accepted that some level of Smart Grid research is necessary to prepare the grid for renewable generation, but it contended that the $4 million in expenditures proposed under Development OM&A were not sufficiently justified in the evidence and advocated for a reduction of $2.0 million for each test year. Energy Probe noted that costs actually incurred in this category as of June 2010 were zero.

VECC also commented on the paucity of evidence and the absence of a business case analysis in support of Hydro One's RD&D and Smart Grid budgets. While the RD&D budget is intended to enable the testing of the feasibility of emerging technologies, VECC notes that Hydro One conceded that the expenditures are set out at a high level with no definitive project by project analysis. VECC supported other intervenors' conclusions that these budgets should be reduced by 50%, for a total reduction of $5.2M per test year.

In its argument over the proposed increases to controllable costs, SEC suggested that the Board freeze Development OM&A budgets at current levels. Board staff noted that no cuts were made in Development and Operations budgets despite the growth of these budgets for both areas and in some cases presumed reduced development work load.

Hydro One rejected the idea that there was a direct correlation between Development OM&A spending and Development Capital spending. It argued that RD&D expenditures are also made in conjunction with many partner organizations and cutting expenditures in research and development would jeopardize Hydro One's capability to assess emerging technologies and make informed investment decisions. In its view any cuts would compromise existing contractual obligations and current projects. Hydro One underlined that Smart Grid work was also essential and necessary.

The Board finds that the budget sought for Development OM&A, with exception of the development work for transmission projects, is quite modest. The Board agrees with Hydro One that there is a need for this organization, perhaps above all others, to have a reasonably vibrant RD&D activity. However the Board shares intervenor concerns that the Company has not provided project by project justification for the planned spending.

The Board accepts Energy Probe's recommendation that Hydro One be required to file a detailed report in its next transmission rates application describing the OM&A activities for Smart Grid undertaken along with an analysis of the results achieved and a description of how they relate to the transmission system.

OPERATIONS

The Operations OM&A program represents the annual expenditures required for the Central Transmission Operations function, operated out of Hydro One's Ontario Grid Control Centre. The Transmission Operations function is concerned with the real time operations of the Hydro One Transmission system equipment, including the monitoring, control, detection and response to equipment operational issues.

Operations OM&A Allocated to Transmission ($ Millions)

	Historic			Bridge	Test	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Operations	28.4	29.1	30.2	31.8	32.7	32.8
Operations Support	18.3	16.6	16.6	22.6	24.8	25.9
Environment, Health and Safety	2.9	1.9	1.5	2.6	3.5	4.0
Large Customer & Generator Relations*	4.3	4.1	4.3	5.2	5.3	5.5
Total	**54.0**	**51.7**	**52.6**	**62.1**	**66.3**	**68.2**

Source: Exhibit C1/Tab2/Schedule 5
*Due to an organization change, in the previous EB-2008-0272 application these costs were included in Shared Services in the Asset Management organization.

In the Operations category, no reductions from the Company’s original proposal were made, and the Operations OM&A budget grows from the 2009 approved level of $53.7 million to $66.3 million in 2011, an increase of 23% in two years. Board staff submitted that the Applicant has not demonstrated that reductions in this category were properly considered, nor is there an explanation as to why spending in this area could not be reduced.

The Board notes that the Company did not provide, for the purposes of its proposed Operations spending, any specific reductions in light of the Minister’s letter. Hydro One does not appear to have subjected Operations spending to the same depth of analysis as other areas of spending.

SHARED SERVICES AND OTHER

A centralized shared services model is used to deliver common services to Hydro One Networks Inc. and its affiliates. These shared services include Asset Management, Information Technology, and Common Corporate Functions and Services (“CCFS”). CCFS services include corporate management, finance, human resources, corporate communications, legal, regulatory affairs, corporate security, and internal audit.

Allocated Transmission Shared Services and Other OM&A ($ millions)

	Historic			Bridge	Test	
	2007	**2008**	**2009**	**2010**	**2011**	**2012**
Common Corporate Functions and Services	64.1	64.5	71.8	81.3	79.7	86.6
Asset Management	25.9	31.8	40.0	33.0	35.5	36.0
Information Technology	46.2	50.7	56.2	68.1	67.5	68.5
Cornerstone	2.7	1.5	4.0	(9.4)	(12.5)	(21.4)
Cost of Sales	14.5	20.5	13.5	15.8	14.9	8.5
Other OM&A	(72.5)	(109.6)	(114.7)	(130.3)	(138.3)	(131.8)
Total	**80.9**	**59.4**	**70.8**	**58.6**	**46.9**	**46.4**

Source: Exhibit C1/Tab2/Schedule 6

In the specific area of Shared Services, VECC submitted that while Hydro One provided reasonable explanations for some of the cost increases, there was no evidence of constraint being applied.

In particular, VECC submitted that one area that warrants a reduction is the $5 million increase in Corporate Communications related to GEGEA activities. VECC argued that given the uncertainties about the resumption of work on GEGEA related projects these costs should be removed from the OM&A budget and any required expenses recorded in a deferral account.

Hydro One submitted that a number of intervenors such as Energy Probe, AMPCO, PWU and Board staff either supported or had no comments about Shared Services OM&A. Only CCC and VECC urged a reduction to Shared Services OM&A related to a particular area of spending.

The Board is concerned that the Company has not provided any explanation as to why cost reductions ought not to be enhanced in this category of spending.

COMPENSATION

Hydro One projects that payroll for 2011 will be $794.9 million and $832.6 million for 2012. This reflects the combined compensation costs for the transmission and distribution businesses. Hydro One stated that due to the nature of its integrated transmission and distribution workforce, separate workforce and compensation data for the transmission business is not available.

Year End Hydro One Networks Inc Payroll (Tx and Dx)

	Historic			bridge	Test	
	2007	2008	2009	2010	2011	2012
Compensation	495.5	566.2 *14.3%*	623.2 *10.1%*	734.9 *17.9%*	794.9 *8.2%*	832.6 *4.7%*

Source: Exhibit C1/Tab3/Schedule 2
* This payroll reflects compensation costs associated with year-end headcounts for all EPSCA, PWU, Society and MCP Transmission and Distribution staff.

Hydro One stated that while it has strived to reduce compensation levels in response to the Board's previous decisions on transmission and distribution (EB-2008-0272 and EB-2009-0096), it faces significant unique Human Resource challenges as a result of:

- Shortages of skilled workers
- Significant portion of current workforce retiring
- The Company's increased work program
- Tight competition for electricity sector workers.

In its evidence, Hydro One described how it meets its challenges through its staffing strategy, recruitment and training. The Company maintains however, that the overall compensation package remains a product of historical factors as well as current and future challenges.

Approximately 90% of the workforce is unionized. Despite efforts and progress to minimize costs and increase productivity through collective bargaining, Hydro One maintains that its ability to reduce compensation in its unionized environment is limited. The revenue requirement reflects a 3% increase in 2011 and 2012 for the PWU members and a 2.5% increase for Society members. This was subject to considerable cross examination and argument from intervenors. For its management staff, Hydro One stated that it has implemented a zero percent increase over the next two years.

BOMA/LPMA and Board staff suggested that the Board require Hydro One to uphold the intent of the Government's net zero policy to PWU members when the current collective agreement expires in March 2011. If Hydro One is unable to negotiate a net zero compensation increase, BOMA/LPMA submits that any increase in cost should be borne by the shareholder. BOMA/LPMA also suggests that the Board disallow amounts consistent with the Board's decision in Hydro One's previous transmission proceeding (EB-2008-0272) for both 2011 and 2012.

The Board disallowed $4 million in compensation costs in the previous transmission proceeding. While the Board did not order a specific reduction in compensation in the recent distribution proceeding (EB-2009-0096), it did establish an overall OM&A envelope and observed that compensation cost, including growth in head count, are one of the areas in which Hydro One must take future action to control expenditure increases.

Board staff relied mainly on the results of the Mercer study to advocate for a reduction in compensation costs of $6 million in 2011 and $7 million in 2012. Hydro One's evidence was that the Mercer study was still valid in this case and indicated that compensation reductions of $6.2 million and $6.9 million for the two test years is comparable to the Mercer-related reductions ordered by the Board in the previous transmission rates case. Staff also highlighted that voluntary exits from the Company were at very low levels, and that high levels of new hiring were indicative that salary levels were not an impediment to hiring.

Hydro One provided a comparison of its compensation to OPG, IESO and Bruce Power and argued that it has demonstrated its ability to constrain compensation increases relative to the other companies despite being in direct competition with them for labour.

SEC's intervention focused on headcounts and compensation levels. SEC noted the fact that Hydro One had not updated its work plan with respect to headcount, and that Hydro One had indicated that the current plan is high by 40-50 positions. Over the five year period from 2007 Hydro One is adding, on average over 600 employees per year.

VECC and SEC also suggested that Hydro One has been overestimating the number of retirements over a number of years. SEC suggested that the problem of retirements never really seems to materialize. With regard to headcount, SEC suggested that 500 or more of the 1230 additional employees proposed for 2010 are in excess of reasonable needs, especially given the additional net 578 to be added in 2011 and 150 in 2012. At the average wage level of $93,153 cited by Hydro One, and without including non-wage compensation, SEC submitted that this amounts to more than $46 million per year during the test period. If it is assumed that 50% is applicable to the transmission side of the Company's business this would amount to a $23 million per year reduction in compensation costs.

SEC agreed with the Board staff submissions to the effect that costs due to compensation should be reduced by $6.2 million and $6.9 million respectively for the two test years in light of the Mercer study findings.

In its evidence, Hydro One referenced a series of comparisons between position descriptions used in its system, and those employed by relevant comparators. SEC questioned these benchmarking comparisons provided by Hydro One, referencing the fact that Hydro One used the Powerline Maintainer position at $35.46 an hour for the comparison, when it would have been more appropriate to use the position of Regional Maintainer ($38.30).

SEC proposed reductions to OM&A totaling $52.8 million including the human resource reductions discussed above.

VECC submitted that Hydro One's total compensation costs are not in compliance with the Board's Direction in its decision in the EB-2008-0272. VECC noted that Hydro One is still not able to provide an estimate of total compensation costs that relates to the applied-for revenue requirement, including an appropriate allocation as between its Distribution business and its Transmission business.

VECC suggested that the primary driver of higher 2011/2012 compensation costs is increases in headcount. Second is the fact that salaries continue to be above industry norms based on the Mercer Compensation studies. The third reason for higher compensation costs is that salaries are increasing at a rate above inflation.

VECC submitted that Hydro One has historically overstated headcounts and recommended the headcounts for the test years be reduced by 50 FTEs which, using an average base pay of $75,000, would result in OM&A costs reductions of $3.75 million in each test year. In addition, VECC also argued that the findings of the Mercer study justify reductions of $6.2 million and $6.9 million respectively for the two test years.

With regard to the wage comparison evidence, VECC suggested that to be meaningful, a wage comparison survey should include annual cost of living data for the comparator group. VECC submitted that Hydro One should be directed to provide a new wage comparison study that includes cost of living data.

VECC also submitted that Hydro One had underestimated the Apprenticeship Training tax credits by at least $1 million in each test year.

On the issue of pensions, Board staff expressed concern with higher pension costs and encouraged the Board to direct Hydro One to move toward higher employee contribution levels to the pension plan in addition to taking steps to increase pension plan performance from the 61st percentile level that Hydro One had so far achieved. VECC also agreed with Board staff that the share of employee contributions to the pension plan should be brought in line with public sector norms of 50%.

Board Findings

The Board notes Hydro One's efforts to address compensation issues highlighted in previous proceedings. However, the Board continues to be concerned about the Company's ability to control the growth in head count and labour cost increases, particularly within its collective bargaining environment. Hydro One has consistently stated that its ability to decrease labour costs through collective bargaining is limited given the increases that have been negotiated in agreements for other electricity utilities. However, the Board agrees with SEC's assessment that the compensation levels at Hydro One have the tendency to push up the amounts that every other utility in Ontario has to pay their staff. The Board does not accept Hydro One's statement that its ability to moderate wage increases is limited in light of wage increases awarded in other electricity utilities. This circularity of dependence between LDCs and Hydro One is obvious and of concern to the Board.

The Board also shares intervenors' concerns that Hydro One's compensation costs are still 17% above the market median and that proposed increases in headcounts are excessive. Central to this problem is the lack of any measureable increases in productivity. In its previous decision, the Board indicated that it did not accept that the productivity portion of the Mercer study could be relied on. The Board still finds this to be so.

The only reasonable conclusion that can be drawn from the evidence in the current case is that there appears to be a disconnect between the compensation levels as reflected in union settlements and the productivity being achieved by the Corporation. This must change.

The Board directs Hydro One to revisit its compensation cost benchmarking study in an effort to more appropriately compare compensation costs to those of other regulated transmission and/or distribution utilities in North America. It is important that the Company be in a position to provide more robust evidence on initiatives to achieve a level of costs per employee closer to market value at its next transmission rate case. The Board will expect compensation increases to be matched with demonstrated productivity gains. Hydro One will risk not recovering all of its compensation costs if it fails to tie compensation cost increases to measureable gains in productivity.

To that end, the Board directs Hydro One to consult with stakeholders about how the Mercer study should be updated and expanded to produce such analyses.

While the Board has approved an overall OM&A envelope and given Hydro One the freedom to apply that spending according to its own priorities, the Board expects that Hydro One will revisit the proposed increases allocated to compensation.

This should provide a signal for upcoming bargaining. With respect to pension contributions, it is the Board's view that in subsequent applications, Hydro One must demonstrate measurable progress towards having its pension contributions reflect those prevailing in the public sector generally. The evidence suggests that an employee contribution level of 50% is the norm.

TAXES OTHER THAN INCOME TAXES

Hydro One projected property taxes of $61.8 million in 2011 and $63.2 million in 2012. This is an increase of 2% in both 2011 and 2012 for the cost of property tax, indemnity payments and rights payments.

Taxes Other than Income Taxes ($millions)

	Historic			Bridge	Test	
	2007	2008	2009	2010	2011	2012
Property Tax	55.2	57.3	58.3	60.4	61.8	63.2
Indemnity Payment	4.5	4.5	4.5	4.5	4.5	4.5
Rights Payment	2.8	2.7	2.4	4.5	4.5	4.5

Source: Exhibit C1/Tab2/Schedule13

Based on the fact that year-to-date June 2010 property taxes are lower than forecast, BOMA/LPMA submitted that test year amounts for property taxes should be reduced by $0.7 million in each year. In its response Hydro One provided an explanation regarding the property tax calculation for the test years, revealing a one time credit due to a tax appeal in 2009.

Hydro One indicated that Rights Payments are currently under review and that the Company is unable to predict the outcome of the timing. The amounts included are budgets used for planning purposes. BOMA/LPMA submitted that given the uncertainty around the quantum and timing of any changes to Rights Payments, Hydro One should be required to maintain current costs of $2.8 million for the test years. BOMA/LPMA also indicated that it did not oppose a variance account to track actual payments.

Board Findings

While the Board will not require a specific reduction in Rights Payments, it will establish a variance account to track the difference between the amount provided for in the revenue requirement and the actual payments.

Harmonized Sales Tax

The 8% Ontario provincial sales tax (“PST”) and the 5% Federal goods and services tax (“GST”) were harmonized effective July 1, 2010, at 13%, pursuant to Ontario Bill 218, which received Royal Assent on December 15, 2009.

Prior to this event the PST would have been included in Hydro One’s OM&A expenses and capital expenditures. PST therefore would have been included in Hydro One’s revenue requirement and therefore recovered from ratepayers through UTR rates.

Now that PST and GST are harmonized, Hydro One will pay the HST on purchased goods and services and is eligible to claim a full input tax credit (“ITC”) on the PST portion paid. Therefore, Hydro One will no longer incur that portion of the tax that was formerly applied as PST.

In the majority of 2010 electricity rate applications the Board ordered the establishment of a deferral account to record the amounts that were formerly incorporated as the 8% PST on capital expenditures and OM&A expenses incurred, but which would now be eligible for an ITC. This treatment was to be implemented to reflect amounts arising between July 1, 2010, the date the harmonization was effected and the time of their next cost of service rebasing application.

In response to an interrogatory, Hydro One initially estimated the reduction in OM&A attributable to the elimination of the PST to be $5.2 million in 2011 and $5.3 million in 2012. The reductions in capital expenditures were estimated to be $42.6 million in 2011 and $35.8 million in 2012. The revenue requirement impact of these combined reductions is approximately $10 million in each year. (Capital expenditure reductions were estimated to contribute $4 million to revenue requirement impact and OM&A accounted for the remaining $6 million.)

Hydro One initially proposed to record the revenue requirement impact of the estimated reduction in its proposed 2011 and 2012 expenditures in deferral account 1592. However, during the course of the oral hearing and subsequently in its final argument, Hydro One indicated that it could reflect the cost impacts between HST and PST in the revenue requirement. The Company indicated that a deferral account was no longer warranted. Hydro One also indicated that it had conducted further analysis of the reduction in revenue requirement driven by harmonization of GST and PST.

Hydro One also updated its estimates of this issue since the oral hearing, revising its estimates of the impacts on revenue requirement to be $7.2M and $10.4M in 2011 and 2012 respectively. The revised impact is due to reductions in OM&A, depreciation, and return on rate base, together with an increase in income tax.

Several intervenors submitted that the cost impact between the HST and PST should be reflected in revenue requirement so that savings can be passed on to customers in the test years.

CCC asserted that the difference between estimated and actual reductions in OM&A should be recorded in a variance account.

BOMA/LPMA argued that the reductions in the test-year revenue requirement should be passed onto customers, especially in an environment where rates are rising significantly. BOMA/LPMA recommended the use of a variance account to capture any variances in the projected reductions in revenue requirement. BOMA/LPMA also noted that it was unclear from the evidence if the reductions in capital expenditures for the last six months of 2010 (i.e. post July 1, 2010) are reflected in the calculation of the test year rate base. BOMA/LPMA estimated the impact to be approximately $1 to $2 million in the test years.

BOMA/LPMA and VECC also noted that the effect of the introduction of the HST is to reduce the working capital amounts from $7.1 million to $0.8 million in 2011 and from $5 million to $3.4 million in 2012. These intervenors argued that the reductions in working capital should also flow through to customers.

In reply argument, Hydro One agreed to pass on the savings to customers by reducing the test year revenue requirement. Hydro One submitted that a variance account was not required, arguing that it would not be able to determine the auditable difference between the estimated and actual impacts given the fundamental difference between PST and HST and the significant volume of transactions which are affected.

Board Findings

The Board finds that after adjusting the OM&A envelope in accordance with this decision, Hydro One will recalculate the resulting HST-related reduction in OM&A and recognize this reduction in its revenue requirement.

RATE BASE AND CAPITAL EXPENDITURES

Hydro One Transmission's forecast rate base for the 2011 test year is $8,378.5 million and for the 2012 test year is $9,134.6 million. The 2011 rate base is 9.7% higher than the 2010 Board approved rate base of $7,636 million. In 2012, the rate base is forecast to grow by 9% compared to 2011.

The Working Capital Allowance for 2011 is $24.5 million and $26.7 million for 2012.

Historical and forecast capital expenditures by major cost category are summarized in the table below. Hydro One also proposed capital expenditures of $126.7 million in 2011 and $198.1 million in 2012 related to projects in its Green Energy Plan. All Green Energy Plan capital investments are included in the Development category and are addressed separately in this decision.

Transmission Capital Expenditures 2009 – 2012[1]

($ million)

Category	Actual 2009	Bridge 2010	Test 2011	Test 2012
Sustaining	300	308.3	424.9	443.4
	7%	*3%*	*38%*	*5%*
Development	516.2	537.9	617.2	456.8
	66%	*4%*	*15%*	*-26%*
Operations	20	10.1	44.3	57.4
	-13%	-50%	*339%*	*30%*
Shared Services	81.5	73.6	66.3	50.6
	-9%	*-10%*	*-10%*	*-24%*
Total Capital Expenditure Budget	**917.8**	**929.9**	**1,151.8**	**1,008.3**
	30%	*1%*	*24%*	*-12%*
Total (Excluding Green Energy Plan)[2]	**917.8**	**929.9**	**1,025.1**	**810.1**
	30%	*1%*	*10%*	*-21%*

[1] Exhibit D1/Tab3/Sch1 p. 2

[2] Reflects the removal of the Green Energy Plan capital investments of $126.7 million in 2011 and $198.1 in 2012 from the Development capital budget.

The submissions of intervenors primarily focused on the appropriateness of the overall capital expenditure budget. Other issues that were raised dealt with adjustments to the various components of rate base.

The following issues are addressed in this chapter:

- Overall Capital Expenditures
- Materials and Supplies Inventory
- Recognition of HST savings on components of rate base
- Allowance for Funds Used During Construction

OVERALL CAPITAL EXPENDITURES

Capital expenditures are forecast to increase by 24% in 2011 and decrease by 12% in 2012. Excluding Green Energy Plan investments, capital expenditures are forecast to increase by 10% in 2011 and decrease by 21% in 2012.

Due to the multi-year nature of transmission projects, not all capital expenditures will be booked to the test-year rate base. Only a portion of the capital expenditures for which Hydro One has sought approval will be in service in the test years. In-service capital additions in 2011 are estimated to be $870.6 million and $1,618.8 million in 2012. In-service capital additions in 2010 are estimated to be $798.2 million. Excluding Green Energy Plan capital additions[3], the capital additions are approximately $859.2 million in 2011 and $1,420 million in 2012. These capital additions represent a year over year increase of 8% in 2011 and 65% in 2012. The significant increase in 2012 capital additions is partly due to the addition of the Bruce to Milton project in rate base.

PWU submitted that the capital budget is not sufficient to sustain the current assets and a further disallowance would exacerbate the deterioration of assets. PWU submitted that Hydro One should be required to submit a plan in its next rates proceeding, setting out a sustaining work program with the aim to improve upon the current demographic profile of major asset classes.

Energy Probe submitted the Company had adequately supported its Sustaining, Operations and Shared Services capital budget. Board staff noted that it did not have any specific concerns with Hydro One's capital budget.

VECC and CCC argued that Hydro One had not made sufficient reductions to its revenue requirement, as it was asked to do by the Minister of Energy in his letter to Hydro One dated May 5, 2010. They argued that the spending cuts to the capital plan were *de minimus.* These intervenors argued that the reductions to the budget are due to the deferment of projects as opposed to specific reductions in the budget. VECC noted that in cross-examination Hydro One's witness confirmed that the focus of the

[3] Green Energy Plan in-service capital additions: $11.4 million in 2011 and 198.9 million in 2012.

reductions was the OM&A budget, as opposed to the capital budget. VECC submitted that the Company had not made any reductions to the Sustaining Capital budget and noted that these expenditures were still well above the Minimum Level. The Minimum Level of spending is determined by Hydro One's risk-based planning process, referenced above and discussed in more detail at ExA/T12/S5.

AMPCO, BOMA/LPMA and SEC questioned Hydro One's ability to achieve its forecasted capital plan and noted that in recent years Hydro One's actual capital expenditures had been consistently below Board approved levels. In light of the under-spending, AMPCO argued that customers should not be required to pay for capital projects Hydro One is not able to complete. BOMA/LPMA submitted that due to the under spending Hydro One had recovered in rates significant costs which had not materialized. AMPCO noted that in 2007 and 2008 Hydro One's actual capital expenditure was below Board approved expenditure by approximately $200 million. Similarly, BOMA/LPMA noted that in 2009 and 2010 Hydro One had under-spent by $150 million, but still recovered the amount in rates. SEC supported BOMA/LPMA's analysis.

AMPCO proposed a variance account to capture the reduced revenue requirements associated with under spending. BOMA/LPMA proposed a 5% (or approximately $52 million) reduction in capital expenditures in each of the two test years. SEC argued for a 10% reduction and submitted that this would provide a "strong encouragement – at a relatively low cost – for Hydro One to improve its capital planning process for the future" BOMA/LPMA also noted that the Sustaining, Operations and Shared Services capital budget was above the Minimum Level of spending by approximately $100 million. BOMA/LPMA argued that while it may not be prudent to reduce sending to the Minimum Level, it was appropriate to reduce it to a level that is at the mid-point between the proposed expenditure and the Minimum Level.

CME submitted that the Board should adopt an envelope approach to the issue and should determine an overall amount for each investment category.

CME also submitted that the Bruce to Milton project should be removed from the 2012 rate base. CME argued that it was overly optimistic to expect the project to be in service in 2012. BOMA/LPMA submitted that the evidence suggests that considerable risks remain that could prevent Hydro One from completing the project by 2012. BOMA/LPMA proposed that in light of the risks, Hydro One should establish a variance account to track the change in the 2012 revenue requirement if the Bruce to Milton project is not closed to rate base as currently projected. BOMA/LPMA argued that a variance account mechanism provided ratepayers with protection in case the project was delayed, while allowing Hydro One to recover the revenue requirement associated with the project if it is completed on time.

Hydro One responded that its capital expenditure forecast is based on a rigorous planning process that had adequately considered the effect on consumers' bills and the need to invest in the transmission system. Hydro One submitted that its capital plan must be assessed based upon the evidence before the Board and that it would be inappropriate to disallow necessary projects simply because consumers may also face increases on other components of their bill, such as the commodity cost. Hydro One further submitted that the evidence, combined with a lack of any specific criticism from intervenors and Board staff, demonstrates that the proposed capital expenditures are appropriate, and that they ought to be approved as requested.

Board Findings

The Board accepts Hydro One's overall test year capital expenditure budget for 2011 and 2012. This approval pertains only to the expenditures related to non-Green Energy Plan projects. The appropriateness of capital expenditures related to Green Energy Plan projects are addressed separately in this decision.

As noted earlier, a portion of the test year capital expenditure budget is related to projects that will not be in service in the test years. These projects are classified as Category 3 and Category 4 projects. The majority of spending related to these projects is in Development Capital, with a few projects in the Sustaining Capital category[4].

With respect to Category 3 projects, Hydro One sought guidance from the Board on the appropriateness of project need, the proposed solution, and the recoverability of the project cost. While the Board has approved the overall capital budget, it will not provide Hydro One with the guidance it has sought in relation to these projects. An advance ruling on the appropriateness of project need, proposed solution or the recoverability of project cost is premature at this time. In the Board's view the appropriateness of project need and prudence of costs are best considered when Board approval is sought to add these projects to rate base.

With respect to Category 4 projects, Hydro One did not seek approval for these projects in this application. The Company proposed to seek approval for these projects in future Section 92 applications. The purpose of including the spending on these projects in the capital budget was to inform the Board of the Company's future intent. The Board therefore believes that it does not need to address these projects in this application.

The remaining portion of the Development Capital budget is related to projects that will be in service in the test years. These projects were classified as Category 1 and Category 2 projects. In approving the overall capital budget, the Board approves the capital expenditures related to these projects.

The Board is not persuaded by the submissions of those parties that argued for a reduction to the capital budget based on an analysis of the historic spending levels

[4] Board staff interrogatory 64

compared to the historic levels allowed for in rates. Nor is the Board persuaded that it is appropriate to reduce the spending to the Minimum level or close to it, as proposed by some intervenors.

While the Board accepts that a retrospective view of an applicant's activities is important and informative in the consideration of future spending, it has little value in isolation. This is a future test year application and historic activities must be considered in the context of the applicant's evidence supporting its projections of both future need and ability to execute its plan to meet those needs.

Hydro One has satisfied the Board that it has expended considerable effort and care in preparing its plans and organizing itself in an effort to improve its ability to execute its plan. In particular, its evidence pertaining to its outsourcing and human resource management is demonstrative of this effort.

In recognition of these initiatives the Board does not consider it necessary to further encourage Hydro One's demonstrated behaviour with notional reductions based on historic plan execution results. In the Board's view Hydro One has provided a reasonable capital spending plan that has sufficient evidentiary support to be used in its totality to derive its revenue requirement for the test years.

The Board's detailed findings and reasons for its non-acceptance of Hydro One's proposal to add its CWIP related to its Bruce to Milton project to rate base are found elsewhere in this decision. Given the Board's decision on this proposal it will address a disputed issue pertaining to rate base and the prospective timing of the completion of the Bruce to Milton project.

BOMA/LPMA submitted that due to the risks that remain that could prevent Hydro One from completing the Bruce to Milton project by 2012, Hydro One should establish a variance account to track the change in the 2012 revenue requirement if the project is not closed to rate base as currently projected. Hydro One did not respond to this particular BOMA/LPMA argument in its reply argument.

The Board accepts the BOMA/LPMA submission and directs Hydro One to establish a variance account for this purpose. As submitted by BOMA/LPMA, the variance account mechanism will provide ratepayers with protection in case the project is delayed, while allowing Hydro One to recover the revenue requirement associated with the project if it is completed on time.

This mechanism to ensure the alignment of the projected rate base with the matching revenues is not normally required by the Board. However, given the level of uncertainty of the project completion coupled with the quantum of the impact on the revenue requirement, the Board considers it appropriate in this case.

MATERAILS AND SUPPLIES INVENTORY

Hydro One's materials and supplies inventory forecast for 2011 and 2012 is $17.4 million and $21.7 million. The materials and supplies inventory forecast is derived by averaging the previous year's year-end inventory and the current year-end inventory. Table 1 at Ex D1/T1/S4 provides the actual inventory levels for the period 2007 to 2010.

BOMA/LPMA argued for a reduction to the material and supplies inventory forecast, noting that the year over year increase in inventory was significant and that the increase had not been adequately justified. BOMA/LPMA noted that the projected increase in inventory was greater than the growth of assets in service.

BOMA/LPMA also questioned Hydro One's ability to accurately forecast inventory. BOMA/LPMA noted that in 2009 and 2010, actual inventory was $11.7 million and $12.7 million, whereas Hydro One's forecast was significantly higher at $36.7 million and $38.7 million respectively. According to BOMA/LPMA the test year inventory forecast should be reduced to $15.8 million and $17.5 million respectively.

Hydro One responded that effective January 1, 2008 it retrospectively adopted Canadian Institute of Chartered Accountants' (CICA) Handbook *Section 3031 - Inventories*, which required it to reclassify certain major spare parts and standby equipment that were previously classified as inventory as fixed assets. Hydro One explained that the Board approved materials and supplies inventory estimate for 2009 and 2010 was based on the old CICA standard, while the actual inventory for 2009 and 2010 reflects the adoption of the new standard. With respect to the increase in test year inventory levels, Hydro One noted that the increase was due to the growth in the transmission work program, specifically the Sustaining capital program.

Board Findings

The Board accepts Hydro One's explanation of the drivers of the fluctuations in the recorded amounts in inventory and accepts that the increase is commensurate with the increase in the Sustaining capital program. The Board accepts Hydro One's forecast as adequate for calculation of this part of the revenue requirement.

RECOGNITION OF HST ON COMPONENTS OF RATE BASE

The 8% Ontario provincial sales tax ("PST") and the 5% Federal goods and services tax ("GST") were harmonized effective July 1, 2010, at 13%. Now that the PST and GST are harmonized, Hydro One will pay the HST on purchased goods and services and is eligible to claim a full input tax credit on the PST portion paid. Therefore, Hydro One will no longer incur that portion of the tax that was formerly applied as PST.

Hydro One estimated the reduction in capital expenditures due to the elimination of the PST to be $42.6 million in 2011 and $35.8 million in 2012. The revenue requirement impact of these reductions is approximately $4 million in each year. (When OM&A reductions are considered the impact on revenue requirement is approximately $10 million). Hydro One revised its estimates in its final argument, as noted in the OM&A section of this decision.

BOMA/LPMA argued that the reductions in the test-year revenue requirement should be passed onto customers, especially in an environment where rates are rising significantly. BOMA/LPMA recommended the use of a variance account to capture any variances in the projected reductions in revenue requirement. BOMA/LPMA also noted that it was unclear from the evidence if the reductions in capital expenditures for the last six months of 2010 (i.e. post July 1, 2010) are reflected in the calculation of the test year rate base. BOMA/LPMA estimated the impact to be approximately $1 to $2 million in the test years.

BOMA/LPMA and VECC also noted that the effect of the introduction of the HST is to reduce the working capital amounts from $7.1 million to $0.8 million in 2011 and from $5 million to $3.4 million in 2012. These intervenors argued that the reductions in working capital should also flow through to customers.

In reply argument, Hydro One agreed to pass on the savings to customers by reducing the test year revenue requirement. Hydro One submitted that a variance account was not required.

Board Findings

The Board accepts Hydro One's response that it will reflect cost reductions related to HST in its revenue requirement. The Board approved Hydro One's HST related adjustments in the previous section on OM&A. Hydro One shall recalculate the capital-related HST effect on revenue requirement in accordance with this decision.

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION ("AFUDC")

AFUDC is the interest rate used for construction work in progress. The AFUDC in 2011 is $54.4 million and $63.2 million in 2012. The AFUDC rate is 5.6% in 2011 and 6.1% in 2012.

BOMA/LPMA submitted that the AFUDC estimate of $73.6 million in 2010, which is based on a rate of 4.9%, is over stated. BOMA/LPMA noted that the actual AFUDC rate in 2010 was 4.34%. Based on the revised rate, the AFUDC in 2010 is lower by $6.4 million. BOMA/LPMA submitted that the reduction in the 2010 AFUDC should be reflected in the calculation of the test year rate base.

BOMA/LPMA also noted that the test year AFUDC is based on interest rate data from October 2008. In BOMA/LPMA interrogatory 28, Hydro One was asked to provide AFUDC estimates based on more recent economic data. The result is a reduction in test year AFUDC of $3.2 million in 2011 and $2.1 million in 2012. BOMA/LPMA submitted that Hydro One should reflect the reduced AFUDC in the calculation of the test year rate base.

Board Findings

The Board considers the submissions of BOMA/LPMA to be reasonable and directs Hydro One to calculate its rate base for the test years using updated data.

GREEN ENERGY PLAN

In a letter dated September 21, 2009, the Minister of Energy and Infrastructure instructed Hydro One to "immediately proceed with the planning, development and implementation" of certain transmission projects. The twenty major transmission projects in Schedule A of that letter and five enabling projects in Schedule B were developed by the Ontario Power Authority ("OPA") and Hydro One to facilitate the connection of "renewable generation likely to be forthcoming through the feed-in tariff program."

Hydro One's Green Energy Plan (the "GE Plan") is based entirely on the Minister's September 2009 letter. That is, all projects and associated timelines identified in Schedule A and B of that letter are included in the GE Plan. The GE plan covers a ten year period from 2010 to 2020. The total gross cost of the GE Plan is $7.7 billion, of which the cost of the Schedule A projects is $6.9 billion and the cost of Schedule B projects is $840 million.

Hydro One sought Board approval for the overall GE Plan and the capital expenditures of $126.7 million in 2011 and $198.1 million in 2012. Specifically, the capital expenditures are on two Schedule A projects and a number of Schedule B projects as set out in the Plan.

In addition to capital expenditures, Hydro One proposed to spend $35.7 million in 2011 and $46.7 million in 2012 on OM&A development work. The OM&A costs are in a deferral account and do not affect the test year revenue requirement.

The following issues are addressed in this chapter:

- GE Plan Approval
- Appropriateness of test year expenditures in the GE Plan
- Cost Responsibility

GE PLAN APPROVAL

As noted, Hydro One's GE Plan is based on the Minister's September 2009 letter. On May 7, 2010, the Minister sent a letter to the OPA requiring new advice regarding transmission planning. Specifically, the Minister directed the OPA to "develop and submit an updated transmission expansion plan updating the September 2009 instruction to Hydro One"[5]. As a result of this letter, and pending updated instructions

[5] Exhibit I/Tab1/Schedule 98/Attachment 1

from the Minister, Hydro One suspended work on all projects. At the oral hearing, Hydro One witnesses confirmed that new direction had not been provided.

In argument-in-chief, Hydro One submitted that it is not seeking Board approval for individual projects in the GE Plan, but is asking the Board to approve the GE Plan conceptually. Hydro One submitted that at a minimum, the Board should approve the capital expenditures on Schedule B projects. Hydro One further submitted that it intended to file an updated five year transmission Green Energy Plan in its next rate application.

Board staff submitted that the level of uncertainty around certain aspects of the GE Plan and the pending instructions from the Minister make it difficult to assess the appropriateness of the Plan, even at a conceptual level. Board staff submitted that the Board should wait for an updated Plan, as the company had indicated it was willing to provide as part of its next rate application. Notwithstanding the concerns with the appropriateness of the overall GE Plan, Board staff submitted that the Board could approve the GE Plan in part. In this respect, Board staff agreed with Hydro One that the Board should at a minimum consider approving those projects that are expected to go ahead in the test years.

CME submitted that the Board should refrain from approving the GE Plan on a conceptual basis. CME argued that the issue of GE Plan approval should be revisited after updated instructions are provided to Hydro One. Until that happens, CME submitted, the Board should confine its approval to those GE Plan projects that are ready for implementation.

BOMA/LPMA submitted that there was no value in approving the GE Plan on a conceptual basis and that the Board should defer approval until more information is available. BOMA/LPMA further submitted that the Board should confine its approval to the Schedule B projects proposed in this application.

CCC submitted that given that the Minister's September 2009 instruction on which the GE Plan is based is currently under review, it is difficult to assess the appropriateness of the Plan. CCC supported the investments on the three Short-Circuit upgrades, however noted that the Board's approval of these projects should not imply that the Board is approving part of the Plan.

AMPCO submitted that the Board should not approve the Plan and recommended that this aspect of the proceeding be kept open until such time that an updated plan can be filed. AMPCO also submitted that development work on all projects for which Hydro One receives cost approval and for which the Board invites licence transmitters to submit plans, should be made publicly available during the competitive bidding process.

Energy Probe and VECC submitted that it is not reasonable for the Board to approve the GE Plan conceptually and recommended the Board postpone the approval of the Plan until such time the OPA's advice is known and the impact of that advice assessed.

PWU submitted that it had no comment on the appropriate mechanism or terminology that the Board should use to address Hydro One's request for a "conceptual" approval of the GE Plan. PWU noted that whatever mechanism is pursued, the Board's decision should not prejudice the approval of future Green Energy projects.

Hydro One responded that the GE Plan as filed is conceptually appropriate in light of the objectives of the *Green Energy Act*. Hydro One submitted, "the plan at this time is "conceptual" because circumstances changed after it filed the Plan". Hydro One noted that the vast majority of the spending is beyond the test years and approval of the Plan in no way binds the Board with respect to future expenditures. Hydro One clarified that it is not seeking project specific approval, but rather approval of the overall Development capital budget.

Board Findings

In the Board's view, for the purposes of its green energy plan approval role, the terms "conceptual" and "plan" are poor companions. The development of a plan, properly designated as such, involves a careful, detailed, blueprint-like process which has involved all of the necessary parties, taking into account all of the reasonably conceivable contingencies, and made provision for a small number of well researched and fully costed outcomes.

That is not to say that plans ought not to be somewhat flexible in order to deal with genuinely unanticipated circumstances. But the purpose of the plan, especially a plan directed to the transmission system, is to provide very detailed and thoroughly researched engineering guidance to its implementers. In the present case, to the extent that the Hydro One proposal is conceptual, it cannot qualify as a plan. There is no role for Board approval of conceptual plans.

In a letter to the industry dated October 27, 2010 the Board indicated its intention to develop a regulatory framework, informed by the Green Energy Act and other relevant considerations including total bill impact. In that letter the Board referenced the importance it places on the process involved in the development of plans. Specifically, the Board expressed interest in the development of a planning process that coordinated planning activities on a regional basis. The Board will be undertaking a consultation respecting its regulatory framework, and it is safe to say that matters of transparency, inclusiveness and coordination will be engaged in that consultation.

Apart from this consideration, the Board has concerns about approving in any degree projects that are not reasonably expected to be in service during the test year periods. There are two reasons for this reluctance.

First, the Board is concerned that its approvals not become a factor driving one program or project at the expense of another. The simple fact that the Board has approved a project could have the effect of advancing that project even though others may be more advisable.

Second, the Board is concerned that in this case its approval process ought to be directed to issues genuinely engaged within the test period. In the Board's view, decisions respecting these projects should be made within the context, and in light of all of the evidence presented by the Applicant in its cost of service review. There may well be exceptions driven by exigencies, and the Board can deal with those in due course. The Board's processes are flexible enough to enable it to be suitably responsive to emerging requirements. But it is inappropriate for a panel determining rates for 2011 and 2012 to be reaching very much beyond that time frame in its approvals. This is especially so in an environment which is so obviously dynamic. While the Minister's letter of September 2009 urged Hydro One to embark on an extremely challenging development process, the letter of May 7, 2010 to the OPA required an updated transmission plan that could significantly change the original instructions to Hydro One.

In this case, the development of and approval of a plan that reaches much beyond the test period would seem to be inadvisable.

It is clear that the pace at which significant system expansions and enhancements are to be undertaken is a matter of concern to all participants in the Ontario market at this time. This factor was also highlighted in the Board's letter of October 2010. In the Board's view, in the circumstances of this case, it is most appropriate for it to approve what comes before it genuinely connected to the test period, and not much more.

Accordingly, in the circumstances of this case, the Board will not approve the overall Green Energy Plan on a conceptual, or any other basis.

APPROPRIATENESS OF TEST YEAR EXPENDITURES

The OM&A and Capital expenditures are summarized in the table below:

GREEN ENERGY PLAN SUMMARY OF OM&A AND CAPITAL EXPENDITURES ($ Millions)				
	OM&A (Def A/c)		**Capital**	
	2011	**2012**	**2011**	**2012**
Schedule A Projects	$ 35.7	$ 46.7	$ 4.5	$ 22.6
Schedule B Projects			$ 120.8	$ 168.2

Projects less than $ 3 million			$ 1.4	$ 7.3
Total Expenditure	**$ 35.7**	**$ 46.7**	**$ 126.7**	**$ 198.1**
In-Service Capital Additions			**$ 11.4**	**$ 198.9**
Impact of Capital Additions on Revenue Requirement			**$ 0.9**	**$ 10.3**

Hydro One sought Board approval for a test-year capital budget of $126.7 million in 2011 and $198.1 million in 2012. This includes spending on two Schedule A projects and a number of Schedule B projects.

The two Schedule A projects are the Sudbury to Algoma Project and the Northwest Transmission Project. These projects are not in the test year rate base and do not impact the test year revenue requirement. Hydro One submitted that it was not seeking project approval in this proceeding and will do so in a future Section 92 application. The reason for including the projects was to inform the Board of Hydro One's future intent.

The remaining amounts in the capital budget are for Schedule B projects. The projects in this category include:

- Short Circuit upgrades to Leaside TS, Hearn TS and Manby TS,
- Two Enabling TSs,
- One Static Var Compensator,
- Six In-line circuit breakers,
- Protection upgrades, and
- Transfer Trip facilities.

Not all schedule B projects will be in-service in the test years. Of the total capital expenditure that Hydro One sought approval for, only $11.4 million and $198.9 million will be added to the test-year rate base. The projects that will be in-service in the test year include the Short-Circuit upgrades to Leaside TS and Hearn TS, two In-line circuit breakers, Protection upgrades and Transfer Trip facilities. The Schedule B projects that will not be in-service in the test years are Short-Circuit upgrade to Manby TS, one Static Var Compensator, two Enabling TSs and four In-Line circuit breakers. Hydro One classified the latter category as "Category 3" investments. With respect to these investments Hydro One states, "it is seeking guidance from the Board on the appropriateness of need, proposed solution and recoverability of project cost".

In addition to capital expenditures, Hydro One proposed to spend $35.7 million in 2011 and $46.7 million in 2012 on OM&A development work. Hydro One did not seek approval for these costs in this proceeding. The OM&A costs are in a deferral account and do not affect the test year revenue requirement.

As noted earlier, on May 7, 2010, the Minister sent a letter to the OPA requiring new advice regarding transmission planning. As a result of this letter, and pending updated instructions from the Minister, Hydro One suspended work on all GE Plan projects.

Board staff submitted that the projects in the GE Plan are currently under review and there is no guarantee the two Schedule A projects (Sudbury to Algoma and the Northwest Transmission Expansion) will proceed. Accordingly, Board staff submitted that the costs should be removed from the test year capital budget. Notwithstanding the concerns noted with respect to cost responsibility which are discussed later in this Decision, Board staff supported the expenditures on projects that were forecast to be in service in the test years (i.e. Short-Circuit upgrades to Leaside TS and Hearn TS, two In-line circuit breakers, Protection upgrades and Transfer Trip facilities). With respect to the Schedule B projects that have capital spending in the test years, but will not be in-service in the test years (i.e. Short-Circuit upgrade to Manby TS, one Static Var Compensator, two Enabling TSs and four In-Line circuit breakers), staff noted that with the exception of the Short-Circuit upgrade to Manby TS, the need for the remaining projects had not been confirmed by the OPA. Board staff noted that the location of the two Enabling TSs and the four In-Line circuit breakers were not definitively known and submitted that the Board does not have sufficient information to provide the guidance that Hydro One has sought in relation to these projects.

AMPCO submitted that the capital costs of the two Schedule A projects should be removed from the capital budget. With respect to Schedule B projects that are expected to be in service in the test years, AMPCO supported the capital expenditure on the Short-Circuit upgrades and one In-line circuit breaker. AMPCO noted that Hydro One was able to definitively establish that only one in-line circuit breaker will be in service by 2012 and accordingly submitted that the cost of the second In-line circuit breaker should be removed from the test year rate base. With respect to Schedule B projects that will not be in service in the test years, AMPCO supported Board staff's position. With respect to OM&A costs, AMPCO submitted that Hydro One should not be allowed to undertake any spending on development work on Schedule A projects until such time that an updated GE Plan is filed.

BOMA/LPMA supported the capital expenditure on the three Short-Circuit upgrades. BOMA/LPMA noted that it was not appropriate to defer these projects given the short remaining life of the assets.

CME supported the spending on the Schedule B projects that are to be booked to the test year rate base, noting that the Board should consider approving those projects that are ripe for implementation.

CCC submitted that on a stand alone basis the Board should approve the capital expenditures related to the Short-Circuit upgrades. CCC however noted that the Board's approval of these projects should not be interpreted to mean that the Board is approving any part of the GE Plan. CCC also submitted that the request for the Schedule A projects should be denied. Hydro One also sought approval to clear the 2009 balance of $2 million in the OM&A deferral account. CCC argued that Hydro One had not justified this expenditure and the request should be denied.

PWU submitted that there was strong evidence and support for three Short-Circuit upgrades and argued that the Board reject any request that sought to defer the projects.

Board Findings

With respect to the Schedule A projects, namely the Sudbury to Algoma and the Northwest transmission expansion projects, the Board notes that the Applicant is not seeking any form of approval with respect to these projects.

The Company is seeking approval for the Schedule B projects. The Board is prepared to approve the short-circuit upgrades to Leaside TS, the Hearn TS, the Manby TS, two of the in-line circuit breakers, protection upgrades and transfer trip facilities which have been specifically identified by the OPA. In the case of the Manby TS, the Board notes that it has already endorsed this project in a previous proceeding. These projects (with the exception of Manby) are also expected to be in service within the test year period. In the Board's view, the support for these projects, evidenced by the OPA's endorsement, and, in the case of the Manby TS the Board's own endorsement, together with the fact that they are generally intended to be in service within the time frame governed by this application, makes the Board's acknowledgment reasonable and appropriate.

The same cannot be said of the remaining schedule B projects. Not only would these projects not come into service within the relevant timeframe, but they have not been explicitly endorsed by the OPA. While endorsement by the OPA is not determinative, the Board considers it an important consideration in its assessment of such projects. In the Board's view, in the circumstances of this case, it would be inappropriate to provide the guidance the company seeks with respect to these projects.

It is important to note that the Board's decision to withhold project approval with respect to the remaining Schedule B projects does not inhibit the company from doing whatever it considers to be prudent in preparation for these projects. The primary implication of our failure to specifically acknowledge these projects is that company may need to bring the projects back to the Board for approval once more robust evidence of need is available.

Accordingly, the Board will not provide any guidance to the company with respect to the two enabling TS's, the static VAR compensator and four of the in-line circuit breakers represented in Schedule B.

COST RESPONSIBILITY

Upgrade Short Circuit Capability Projects

Included in Schedule B of the Green Energy Plan were three projects involving the upgrade of short circuit capability at the Hearn, Leaside and Manby transformer stations. No party argued that these projects were not needed, and several intervenors (for example BOMA/LPMA) submitted that the costs of these projects in the test years should be approved.

Board staff, in its questions to Hydro One and its submissions, raised the issue of cost responsibility for the advancement of the upgrade work at Leaside and Manby. The advancement costs are estimated by the OPA to be $5.9 million for Leaside and $4.9 million for Manby. Board staff argued that as the stations are classified as line connection assets, the Transmission System Code ("TSC") would dictate a user pay approach for these advancement costs. This would mean that the advancement costs should not be collected from transmission ratepayers, but contributed by Toronto Hydro Electric System Limited ("THESL"), the transmission customer.

The Board notes that no party, in its final submissions, disagreed with Board staff's interpretation of the TSC in regard to cost responsibility for line connection assets. The OPA supported Board staff's interpretation. However, most parties who made detailed submissions on this issue recognized the potential unfairness of requiring a capital contribution from THESL.

Hydro One, THESL, the OPA and Pollution Probe argued that THESL and its customers are not the sole beneficiaries of the short circuit upgrades. Pollution Probe submitted that Hydro One's proposal is in the best interests of all of Ontario's (as well as Toronto's) electricity consumers, as the encouragement of combined heat and power generation will reduce the need for costlier generation or transmission facilities. The cost of Hydro One's short circuit upgrades should thus be paid for by all of Ontario's electricity consumers. Hydro One and the OPA argued that the need for the work has been driven by the previous connection of generators to the system, and such connection benefits all Ontario electricity consumers.

The OPA further submitted that in the particular circumstances of this case, recovering the advancement costs from transmission ratepayers is consistent with the well-established rate-making principles of fairness, feasibility and non-discrimination, as well as the statutory objectives of the Board. The OPA recognized the difficulties in allocating costs to and recovering costs from the many and varied generators that may seek connection to THESL's system. In addition, if the investments were undertaken at THESL-owned facilities, the Distribution System Code ("DSC") might allow recovery by THESL from all provincial ratepayers of the costs of "eligible investments" to connect renewable generation. The fact that the transformer stations are owned by Hydro One rather than THESL means that this source of recovery is not available, and the OPA submitted that this is arguably discriminatory treatment of generators based on location. To allow recovery from transmission ratepayers, the OPA argued, would be consistent with the Board's statutory objective to promote renewable energy generation.

Board staff also acknowledged as a potential problem that neither the DSC nor the TSC provides guidance on how THESL could recover the capital contribution from connecting generators. However, Board staff was concerned that to allow Hydro One to recover the costs from transmission ratepayers would set an unfortunate precedent. Staff pointed out that at present there is no economic connection test for investments in transmission connection facilities, and permitting recovery of such investments from transmission ratepayers moves the risk of uneconomic connections onto those ratepayers. Board staff urged that if the Board was to allow recovery of the advancement costs in transmission rates, that the Board make it clear that this is a response to a transitional issue, and not a policy for the future allocation of such costs.

The OPA echoed this concern, submitting that if the Board allows recovery of these costs from transmission ratepayers, it should do so in response to the particular issues of this case rather than set a policy precedent for future cost allocation. The OPA further proposed that the Board re-categorize a portion of the Leaside and Manby transformer stations as "network facilities" under the TSC.

THESL and other parties pointed out that there may be a gap in the existing policy framework. The OPA submitted that the issue of cost allocation for upgrades of short circuit capability would benefit from a focussed review led by the Board, and supported by the OPA, transmitters, and distributors. Hydro One supported the OPA's submission, and stated that it the company would fully participate in such a review.

Board Findings

The Board accepts Hydro One's proposal to advance the upgrade work at Leaside and Manby and that the cost consequences of the advancement be included in its revenue requirement.

The Board notes that there has been no argument advanced attacking the merits of the proposed projects. The submissions all focus primarily on the responsibility for the costs to undertake these projects in advance of the projected end of the useful life of the assets. While the projects are included in the Applicant's Green Energy Plan, as the upgrades will allow for the connection of renewable generation, the advancement of the project is also driven in part by the anticipated scheduling difficulties that may arise if the work were to be left to coincide with the Pan Am games, to be held in Toronto in 2015.

It is clear to the Board that the particular circumstances that give rise to the cost responsibility issues in this application are not representative of the types of circumstances to which the prescribed cost responsibility allocation rules contained in the TSC are intended to apply.

The particular circumstances of this case were not precisely provided for in the TSC. The costs result from a relatively minor advancement which is driven by both the early facilitation of renewable sources of energy and prudent scheduling. For these reasons the Board considers it reasonable to apply a pragmatic approach to the cost recovery of the investment that does not result in any undue subsidies being paid by one set of rate payers to another. The Board considers Hydro One’s proposal to meet this desired outcome.

The Board accepts the submissions of Board Staff and the OPA that should this decision be regarded as setting a precedent, there is a risk that the costs of uneconomic investment would be borne by transmission rate payers. The Board therefore wants to emphasize that this finding is a response to a particular transitional situation, and that this finding should not be regarded as an indication of appropriate regulatory treatment for future transmission investments.

Protection & Control for Enablement of Distribution Connected Generation

Hydro One seeks to recover the costs of the Protection and Control (“P&C”) projects D43 and D44 in transmission rates. Although the pre-filed evidence suggested that the work will be done on connection assets, Hydro One proposed that the costs be recovered from transmission ratepayers for two main reasons:

- The investments will have benefits to the entire system, and are not ultimately triggered by the needs of an identifiable customer or customers; and
- Attempting to allocate the costs to customers would be administratively complex and costly, and could act as a barrier to entry.

Board staff submitted that the Board should consider reducing the requested capital budget by $10 million in 2011 and $29.8 million in 2012 to recognize that the facilities in question are classified as connection facilities, and that the TSC prescribes a user-pay approach for such facilities.

Board staff acknowledged that these facilities may have benefits to the larger network system, but argued that where such equipment is installed at connection facilities, the rules in the TSC dictate a user-pay approach for all or part of the costs. Board staff submitted that while there may be complexities and potential unfairness involved in the application of the rules in the TSC and the DSC to the situations described by Hydro

One, the Board should have regard to the danger of the risks of uneconomic investments being passed through to transmission ratepayers.

Hydro One submitted in its reply argument that that it is not possible to identify at this time exactly how many network or connection stations will be affected. Hydro One further indicated that typically, system driven costs are pooled while costs that are customer driven are allocated to the customer. Hydro One stated that in customer driven cases, Hydro One follows the TSC for connection work and charges capital contributions accordingly.

Hydro One further submitted that P&C investments are not like capacity additions. These investments are triggered by the presence of enough generation on the system to require changes to the overall protection settings and facilities. While one generator might trigger the need for these investments at a particular station, the need is driven by existing and future generators, and the benefit extends to all these generators, as well as the load customers served by that station or served by other stations on the same supply or network circuit. It would not be possible at the point in time the need is triggered to identify all of the existing and future potential beneficiaries of the work and allocate costs accordingly. Hydro One provided examples of the integrated nature of the P&C investments to be carried out, and the complexity involved in Hydro One attempting to recover costs from distributors, and in the distributors in their turn attempting to recover costs from the connecting generators.

Board Findings

The Board considers that there is not a compelling parallel between the treatment of the short circuit upgrades applied for in this case and the P&C work identified by the Company. Nor does the TSC recognize any such parallel.

One of the compelling arguments made by the Applicant and the OPA with respect to the rise of the short circuits at Leaside TS is that the increase in short circuits is attributable to all generators close to the station, and in particular the large Portland Generation project of about 550 MW which came into service in 2008. In that regard, one can agree that the strict application of the provisions of the TSC in regard to short circuits would result in an unfair and an unreasonable outcome.

On the other hand, P&C work is triggered and attributable to specific projects. The TSC is very clear that where the P&C work and equipment is installed on connection assets, the costs arising should be the cost responsibility of the entity requiring that the work be done. The P&C work, together with the equipment associated with it that is undertaken at Network Stations is assigned to the Network pool, and therefore there is no ambiguity as to how those costs should be allocated.

The Board considers that to deviate from this approach except in the clearest and most compelling case is unwarranted and could lead to gaming of the system, and the inappropriate "socialization" of costs which should be the responsibility of proponents. The TSC rules are intended in part to also curb uneconomic enhancements of the system.

As is known to the Applicant, requests for exemption from the provisions of the TSC can be made pursuant to the Board's rules. In such an application the Applicant would be obliged to demonstrate why the application of the Code would be inappropriate in the specific circumstances cited.

The pre-filed evidence indicated that the amount of investment in the capital budget of $10 million in 2011 and $29.8 million in 2012 is for work in facilities classified as Transformation Connection. The Board therefore concludes that TSC prescribed user-pay approach for such facilities is appropriate. Consequently Hydro One's capital budget and rate base should be adjusted to remove the amounts attributable to these projects, and a capital contribution be sought from the pertinent distributors.

EARLY INCLUSION OF CWIP IN RATE BASE FOR THE BRUCE TO MILTON PROJECT

Hydro One, as part of its application, sought an accelerated cost recovery mechanism for the Bruce to Milton transmission line project. The company was granted leave to construct this project by the Board in 2008 (EB-2007-0050), and its relevance to the province's green energy policy was reinforced in a recent Ministerial directive to the OPA dated September 17, 2010. The project has been subject to delays and cost escalation. The planned in-service date is December 31, 2012, but Hydro One acknowledged that further delay was possible.

Hydro One previously sought special regulatory treatment for this project, but the proposal was rejected by the Board in EB-2006-0501. The Board did, however, indicate that Hydro One could bring the Bruce to Milton project, or other projects, forward for special treatment if circumstances arose putting the Applicant at risk. Subsequent to that decision, the Board considered the question of special regulatory treatment for infrastructure projects in a generic proceeding (EB-2009-0152), and released a Report entitled "*The Regulatory Treatment of Infrastructure Investment in Connection with the Rate-Regulated Activities of Distributors and Transmitters in Ontario*" on January 15, 2010 (the "Infrastructure Investment Report").

In the present application, Hydro One relied on the Board's Infrastructure Investment Report. The company proposed that one of the alternative mechanisms dealt with in the Infrastructure Investment Report: the inclusion in rate base of construction work in progress ("CWIP") costs (excluding depreciation) before the project is in service, be used as a rate mitigation and smoothing mechanism. Hydro One's evidence, as set out in Exhibit I-1-122, was that the total cost to ratepayers over the life of the project would be lower by $68 million under the early CWIP recovery approach than under traditional regulatory treatment (by which all costs of the project are recovered subsequent to the in-service date).

The main reason put forward by the Company for the proposal was that this CWIP treatment would benefit ratepayers. It did not appear from the evidence that Hydro One was experiencing cash flow problems that would render exceptional treatment necessary.

Board staff and several intervenors analyzed Hydro One's proposal using the factors enumerated at page 21 of the Board's Infrastructure Investment Report. The need for the project was not disputed by any party. Several parties argued that only unusual risks or particular challenges would justify the use of an alternative mechanism, and that the risks cited by Hydro One for this project were common to most transmission projects in Ontario, which are by their nature subject to unanticipated difficulties and delays. Hydro One, in its reply, argued that the Board's Infrastructure Investment Report does not require a project to have “unique” risks, but rather risks in general associated with project completion.

No ratepayer intervenor accepted the Company’s argument that the proposal would benefit ratepayers. Several intervenors (BOMA/LPMA, SEC and AMPCO) tested the sensitivity of the company’s NPV calculations to the discount rate used in the calculation. Exhibit J6.9 demonstrated that the calculated benefit to ratepayers disappears if a discount rate at or above 7.81% is used. These intervenors argued that the cost of capital for Hydro One’s customers is at least 7.81%, and that the early recovery of CWIP costs would actually be a disbenefit to ratepayers.

Hydro One replied to these arguments, pointing out that the company, in its calculations of the NPV of the project, had used the after-tax discount rate based on Hydro One’s cost of capital, a methodology that has been accepted by the Board, and is commonly used for economic evaluations in Section 92 applications when assessing overall project economics and rate impacts. Hydro One did not agree that a proxy for the consumer’s cost of capital should be used, but argued that if a proxy is to be used, then the OPA’s social discount rate is the best proxy. This discount rate is approximately 4%.

Board Findings

In its Infrastructure Investment Report, the Board outlined a series of measures which it would consider on a case-by-case basis to assist regulated utilities in meeting their obligations. In large part that Infrastructure Investment Report was predicated on the view that both distributors and transmitters may be faced with extraordinary infrastructure building requirements as a result of the Government’s green energy policy. There was and is a concern that in meeting the government's aggressive requirements under the *Green Energy Act*, utilities could be put at risk unless they had confidence, and the general business community had confidence, that they could complete requisite projects without undue risk of failed or dangerously slow cost recovery associated with these projects.

In the Infrastructure Investment Report, the Board was mindful that in some circumstances, the underlying reliability or safety of supply which characterizes the Ontario electricity distribution and transmission systems could conceivably be compromised if utility resources were overburdened or stretched too thin in meeting infrastructure expansion requirements.

A number of measures were identified, including accelerated CWIP recovery, adjusting depreciation, and project-specific capital structure or rates of return. The Board also indicated that if other measures addressing the same issues were to be proposed by transmitters or distributors, the Board would give them due consideration.

In the instant case, Hydro One proposes that the acceleration of CWIP inclusion in rate base would provide a benefit to ratepayers. Its submission is that including costs related to construction associated with the Bruce to Milton project into rate base as they are incurred, rather than at the time they are placed in service, lowers the overall cost of the project to ratepayers, and would also serve as a rate smoothing and mitigation mechanism.

First, the Board would note that the Infrastructure Investment Report on alternative treatments for costs incurred in infrastructure development did not direct itself to issues related to rate reduction, mitigation or smoothing. The Board takes it as a given that where alternative methods may be used which are likely to result in lower rates, the utility has an obligation to explore, and where reasonable, advance such alternatives. The purpose of the Infrastructure Investment Report was to assist utilities in meeting their obligations in a period during which their resources may become unreasonably stretched.

It is clear from the evidence in this case that Hydro One is not experiencing cash flow or other financial difficulties in meeting its infrastructure obligations, including the very demanding project for which alternate recovery is being sought. There was no suggestion in the evidence that the Applicant's ability to meet the prevailing reliability and safety expectations of its customers was in any degree compromised by its Bruce to Milton construction project.

Further, the Board notes that the Company is completely and unalterably committed to the completion of this project. This is not a case where a utility, in looking forward to a proposed project, submits that completion of the project would compromise its financial integrity. In such cases it is reasonable for utilities to argue for alternate treatment of their expenditures as a species of inducement to encourage, indeed in some cases make possible, completion. Here, the Company is fully committed to the project, on the terms and conditions underpinning the Board's approval of the project, and is not advancing any assertion that the project has become an unsustainable burden.

As the Board considers the rate reduction argument made by the Company, we must consider its net present value calculation for the project. The Company has indicated that it has used its own cost of capital in assessing the relative value of advancing the inclusion of construction costs into rate base. In conducting the economic evaluations required for construction projects it has become usual to use the proponent's cost of capital as an input. This approach is indeed appropriate in the normal course of economic evaluations. But in this case intervenors agued that a different objective is being served, namely the calculation of the ratepayer benefit associated with the Company's proposal. A consideration of the ratepayer benefit necessarily requires a consideration of the appropriate cost of capital/opportunity cost to be applied. The Company has suggested first that using its cost of capital for the evaluation should be determinative, and, in the alternative that the OPA's social discount rate should be used.

Both of these proposals were strongly resisted by a number of intervenors.

It is the Board's view that the appropriate approach to be used in this comparison is to consider a comparison that is based on a proxy for the opportunity cost of money experienced by the typical ratepayer. That number is difficult to determine, but could very well exceed 7.8%, at which point the argued-for advantage to customers disappears.

As to the consequential mitigation and rate smoothing, the Board is not convinced that these effects are likely to be particularly meaningful to Hydro One's transmission customers. Mitigation and rate smoothing are complicated concepts. Generally, it is important that ratepayers not be confronted with increases that are of such a magnitude that they create undue hardship. It is also true that volatile rates are very unwelcome to consumers. However, it is also important that consumers have a very clear picture about the cost of the services that are being provided to them, the origins of those costs, and the fact that sooner or later all of these costs will be borne by ratepayers. While mitigation and rate smoothing can be useful regulatory instruments, they ought not to be overused to the extent that consumers fail to appreciate the direct and unavoidable consequences of utility activities, including infrastructure expansion.

Furthermore, the evidence has shown that the Company's proposal to include CWIP in rate base will result in higher rates for the first 12 years of recovery of the project costs. The Board is not persuaded that regardless of the discount rate used, an alternate approach which results in higher rates to customers until 2024 should be adopted in the present environment.

Accordingly, the Board denies the Company's request for the accelerated inclusion of CWIP into rate base with respect to the Bruce to Milton project.

BOMA/LPMA made two further suggestions in its argument. First, that the Board should consider using the actual CWIP rates to calculate the amount of AFUDC to go into rate base in the test years, with a variance account to track the impact of the project on rate base in 2012. Secondly, BOMA /LPMA suggested an alternative approach that would allow the company to expense AFUDC during the test years rather than capitalizing these amounts. BOMA/LPMA emphasized, however, that the Company should be allowed to expense AFUDC only if the Board found that the standard regulatory treatment of allowing capitalized costs into rate base upon plant coming into service was inadequate for the Bruce to Milton project. The Board finds that the standard regulatory treatment is adequate in the circumstances of this application.

CAPITAL STRUCTURE AND COST OF CAPITAL

The table below summarizes the capital structure and cost of capital for the two test years in Hydro One's original application.

	2011				2012			
Deemed	**$M**	**%**	**Cost Rate (%)**	**Return ($M)**	**$M**	**%**	**Cost Rate (%)**	**Return ($M)**
Long-term Debt	$4,692.0	56.0%	5.67%	$265.9	$5,115.3	56.0%	5.64%	$288.3
Short-term Debt	$ 335.1	4.0%	3.99%	$13.4	$365.4	4.0%	5.00%	$ 18.3
Common Equity	$3,351.4	40%	10.16%	$ 340.5	$ 3,653.8	40.0%	10.41%	$380.4
Total	**$ 8,378.5**	**100.0%**	**7.40%**	**$ 619.7**	**$ 9,134.6**	**100.0%**	**7.52%**	**$ 687.0**

Hydro One has filed its capital structure and cost of capital in a manner that was consistent with the Board's December 11, 2009 Report on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084) ("the Cost of Capital Report").

Short-Term Debt

Hydro One's deemed amount of short-term debt is 4% of rate base. The methodology reflected in the Cost of Capital Report provides that the short term rate is calculated as the average Bankers' Acceptance for the 3 months in advance of the effective date for the rates, plus the average calculated spread.

Variable rate debt, which pays interest based on the bankers' acceptance rate, has been included as part of the deemed short term debt amount of 4%. For Hydro One Transmission the deemed short-term rate is 3.99% for 2011 and 5.00% for 2012. These rates are calculated using the November 2009 Global Insight Forecast plus a spread of 150 bps, which is an estimate of the spread that would be charged to Hydro One to obtain a short-term loan in the bank market.

Hydro One assumes that the deemed short term debt rate for each test year will be updated in accordance with the December 11, 2009 Cost of Capital Report, upon the final decision in this case.

Long-Term Debt

Hydro One's long term debt rate (56% of rate base) is calculated as the weighted average rate on embedded debt, new debt and forecast debt planned to be issued in 2010, 2011 and 2012.

As Hydro One has a market-determined cost of debt, the weighted average long term debt rate is also applied to any notional debt that is required to match the actual amount of long term debt to the deemed amount of long term debt, consistent with the Board's Decision in EB-2008-0272.

Return on Equity

The Return on Equity of 10.16% for the 2011 test year and 10.41% for the 2012 test year is based on the Board's formulaic approach adopted in the Cost of Capital Report, using the Long Canada Bond Forecast for 2011and 2012, based on the September Consensus Forecast and Bank of Canada data which was available in October 2009, and the change in the spread of A-rated Utility Bond Yield. Hydro One assumes that the return on equity for each test year will be updated in accordance with the Cost of Capital Report, upon the final decision in this case.

Board staff, VECC and BOMA/LPMA made submissions on long term cost of debt. SEC supported the BOMA/LPMA position.

Board staff, drawing on evidence updates presented in the case through interrogatory responses, submitted that Hydro One should update its long term debt costs for the new debt it has issued since its original application. Board staff indicated that this is in compliance with the EB-2009-0084 Cost of Capital Report. BOMA/LPMA also submitted that the long term debt rates be updated for actual issuances of debt. BOMA/LPMA cited the reductions in 2011 long term debt costs of $2.3 million and 2012 reductions of $4.1 million, agreed to as reasonable by Hydro One's witness Mr. Struthers.

In addition, BOMA/LPMA submitted that Hydro One should update its forecast of long term debt using the most recent information available, rather than the forecasts compiled using October and November 2009 data. BOMA/LPMA argued that if other rates are updated based on September 2010 information, then long term rates should be updated on the same basis.

VECC supported the arguments of Board staff and BOMA/LPMA and argued specifically that the Board should reduce the allowed medium-long term embedded weighted average debt costs for 2011 and 2012 by $2.3 million and $4.1 million, respectively.

In its reply argument, Hydro One agreed to update its evidence for the actual 2010 debt issues in the final rate order for 2011 rates. In addition when 2012 rates are established in late 2012, Hydro One would update long term debt for with actual 2011 issues.

Board Findings

As a general rule the Board prefers that all rate decisions are informed by the most recent relevant data possible. This case is no different, and it appears that among the parties, including the Applicant, there was a realization that updating portions of the data used in the calculation of the cost of capital was desirable. Accordingly, the Board expects Hydro One to update its cost of capital for ROE and Short Term Debt based on the parameters issued by the Board on November 15, 2010. In addition, the Board also expects Hydro One to make a similar update for its 2012 transmission revenue requirement and rates in the fall of 2011.

In addition, the Board also considers it to be generally desirable to incorporate actual values when they can be used in place of estimates or forecasts.

On the specific issue of long term debt forecasts, the Board relies on the Cost of Capital Report and finds that Hydro One should update its long term debt forecasts to reflect and take account of actual issuances of debt since the time of the original application. These revised forecasts should be used for setting rates in 2011 and in 2012.

The Board is also persuaded by the BOMA/LPMA submission respecting the desirability of consistent updating of all debt forecasts. Accordingly the Board directs Hydro One to update its forecast of long term debt with the most current information, which is September 2010 data. Similarly, when Hydro One updates interest rates in the fall of 2011 for 2012 rates, the forecast of long term debt should also be updated for September 2011 data.

FORECAST OF OTHER REVENUES

Hydro One receives additional revenue from a number of sources which work to offset the transmission rates revenue requirement. For the test years, these other sources of revenues are summarized in the table below:

Transmission Other Revenues Forecast
2011 and 2012

	2009 ($ million)	2010 ($ million)	2011 ($ million)	2012 ($ million)
Secondary Land Use	14.2	11.3	12.6	12.5
Station Maintenance	14.6	2.9	4.6	3.0
Engineering & Construction	3.2	1.5	11.0	6.0
Other	3.2	2.3	3.2	3.2
Total	35.2	18.0	31.3	24.7

Source: Exhibit E1/Tab1/Schedule 2

Related to the external revenue forecast, Hydro One also proposed to discontinue the variance accounts established in the last transmission rates case (EB-2008-0272) for Secondary Land Use, Station Maintenance and Engineering & Construction.

VECC included a number of detailed comments on the external revenue categories. For Secondary Land Use, VECC noted that the forecast revenues for 2011 and 2012 were in line with the current forecast for 2010 ($12.5 million) but less than the actual 2009 revenues of $14.2 million. VECC also noted that the forecast does not include any allowance for one-time events, which sometimes do occur and can only serve to increase revenues. BOMA/LPMA also supported the continuance of the variance account, citing that Hydro One had not demonstrated that it is able to accurately forecast these amounts.

SEC submitted that the forecast for 2007 should be increased to $17.2 million to reflect the last three years of actual results and also supported the continuance of the variance account.

In the case of Station Maintenance, VECC noted that forecast revenues are much lower than actual revenues for 2009 and 2010, mentioning also that Hydro One attributed the decrease to an expected shift in resources to its own work programs. VECC pointed out that Hydro One had a similar rationale in EB-2005-0501 and in EB-2008-0272 and, in both cases, actual revenues were higher than forecast.

VECC submitted that the forecast for Station Maintenance work be rejected by the Board and a forecast based on the historic three year average of $13.4 million be used for 2011 and 2012. This would reduce the Transmission revenue requirement for 2011 and 2012 by $8.6 million and $10.4 million respectively.

VECC pointed out that in the EB-2008-0272 Decision, the Board recognized the uncertainty associated with forecasting revenue in these areas and the one-time events that can increase revenues. In order to ensure that ratepayers receive the benefit of these revenues, the Board established variance accounts. VECC argued that the circumstances had not changed and submitted that Hydro One should be directed to maintain variance accounts for each of these activities.

BOMA/LPMA also supported the continuance of the Station Maintenance and Engineering and Construction accounts indicating that Hydro One is still unable to accurately forecast the revenues, costs and resulting margins associated with these activities. SEC also supported the variance account continuance and that the forecast drop in revenues is unsupported by the evidence.

Board staff and CCC also submitted that these variance accounts be continued until the variances are sufficiently immaterial.

Hydro One, in its reply argument, indicated that it felt that the forecasts for each of these activities were appropriate but also acknowledged the concerns voiced by intervenors and indicated that Hydro One is agreeable to the continuation of these three accounts.

Board Findings

The Board is concerned with the accuracy of the forecasts of other revenue and notes Hydro One's agreement to continue the variance accounts. The variance accounts shall remain in place until Hydro One can demonstrate improved accuracy in the forecasting of these amounts.

As for the forecast amounts themselves for the two test years, the Board finds that in light of the under-forecasting that has occurred in the Station Maintenance account, that Hydro One should revise its forecast for this account. However, the Board is of the view that the VECC recommendation (average of historic three years) is too high considering the fact that Hydro One is moving to reduce this work. The Board finds that the forecast for Station Maintenance be increased to $7 million for each of the test years.

FORECAST OF EXPORT REVENUES

The Board notes that the level of Export Revenue is directly dependent on the Export Transmission Services (ETS) rate decision found later in this document.

For this application, Hydro One assumed that the existing ETS rate of $1/MWh was in effect for the purpose of determining the Revenue Requirement and associated rates for Network Service for 2011 and 2012. For 2011 and 2012, ETS revenue will continue to reduce to the revenue requirement for the Network Pool. The forecast for ETS revenue is $10.1 million and $10.2 million per year for 2011 and 2012, respectively.

Hydro One also requested that the variance account related to export revenue be discontinued for 2011 and 2012 as it asserted that it had sufficient history to allow for a more accurate forecast of this stream of revenue.

VECC submitted that the evidence showed that the variance between forecast export revenues and actual revenues is still significant and recommended that this variance account be continued. VECC also noted that continuation of the variance account will also address any increased revenue uncertainty that may arise should the Board decide to adopt an ETS tariff for 2011 and/or 2012 that differs from the $1/MWh. CME supported these submissions.

BOMA/LPMA noted that the forecast of export revenue was shown to be consistently low over the 2007 to 2010 period. Based on this, BOMA/LPMA submitted that the Board should increase the export revenue forecast for both 2011 and 2012 to $14.0 million. This is the average of the actual export revenue for 2005 through 2009, but excluding the $24.6 million recorded in 2008, resulting in an increase in export revenues of $3.9 million in 2011 and $3.8 million in 2012 from that forecast by Hydro One. These increases are roughly in line with the 36% under forecasting average for the 2005 through 2009 period. BOMA/LPMA also recommended that the variance account be continued, given Hydro One's 'terrible' record of forecasting export revenues.

BOMA/LPMA also recommended that the variance account be used to account for any change in export revenues that could arise from a change in the ETS rate.

SEC did not make a specific submission on the level of Export Revenues but did recommend an increase in the ETS tariff to at least $3.00/MWh by January 1, 2011. This would increase the export revenue that would offset transmission rates. CCC submitted that the variance account be continued, arguing that Hydro One did not present sufficient evidence to eliminate this account.

In its reply argument, Hydro One did not comment on the level of Export Transmission revenue, but did not oppose continuing the Export Revenue variance account.

Board Findings

The issue of export revenues is directly dependent on the findings of the Board on the ETS rate. As indicated in the Export Transmission rate section of this decision, the Board has determined that the ETS rate will be $2/MWh for both 2011 and 2012. Therefore, the Board instructs Hydro One to amend the estimate of export revenues to $16 million for both years. The Board will also order that the variance account be maintained to address the forecast uncertainty of these revenues.

DEFERRAL AND VARIANCE ACCOUNTS

Disposition Balances and Disposition Period

Hydro One requested the disposition of the December 31, 2009 credit balance of $7.4 million including interest forecasted to December 31, 2010. Three of the five accounts had credit balances, and two accounts had debit balances as of December 31, 2009. Hydro One proposed to dispose of a total of $12.5 million of the credit balance over one year to mitigate the impact of the requested rate increase in 2011; and $5.1 million of the debit balance over two years.

Deferral/Variance Accounts
Balances as of December 31

Account Description	Account Number	Balance Dec. 31/09 $Million	Balance Dec. 31/10 $Million
Export Service Credit Revenue	2405	(4.8)	(4.9)
External Secondary Land Use Revenue	2405	(3.2)	(3.2)
External Station Maintenance and E&CS Revenue	2405	(4.4)	(4.4)
Subtotal proposed for disposition over 1 year		**(12.4)**	**(12.5)**
IPSP & Other LT Project Planning Costs	1508	1.9	2.0
Pension Cost Differential	2405	3.1	3.1
Subtotal proposed for disposition over 2 years		**5.0**	**5.1**
Total Balance proposed for disposition		**(7.4)**	**(7.4)**

There was no challenge to the amounts recorded in any other accounts, except for IPSP & Other LT Project Planning Costs account.

CCC submitted that the recovery of IPSP account balance should be denied as there is no evidence that the funds were prudently spent. Hydro One in its reply submission submitted that this account was created pursuant to the Board's decision in EB-2008-0272 to record preliminary planning costs for IPSP and other long term projects, and that Hydro One's pre-filed evidence explained the amounts recorded in the account on a project by project basis.

Hydro One pointed out that it was directed by the Minister in a letter dated September 21, 2009 to “immediately proceed with the planning, development and implementation of Transmission Projects outlined in the attached Schedule A.” In addition, the Board in its decision EB-2008-0272 noted that: “An important consideration in this specific request is that Hydro One’s activities are clearly driven by current Ontario energy policy. Hydro One itself is not the driver behind these expenditures; as the largest transmission utility in the Province, it is responding to the policy drive by the Ontario government to meet certain objectives regarding new generation. Although project plans have not unfolded as originally conceived, there are clear expectations of the largest transmission utility that the planning work for these projects must continue.”

Board Findings

The Board finds that the disposition of the IPSP and Other LT Project Planning Costs account is justified.

In the Board’s view it would be a harsh outcome to deny recovery of these development costs. It is clear that the company was responding in a reasonable fashion to the instructions it had received from the Minister in September, 2009. The Board is confident that the company undertook these expenditures with a high degree of confidence that the instructions provided by the Minister, in this case in his capacity as shareholder, would be enduring and would form part of an ongoing execution of government policy. That the instructions changed some months later was not the fault of the utility.

In future, the Board may be less willing to recognize expenses incurred in response to the shareholder’s direction, when that direction is given in that capacity. Going forward, such instructions need to be seen as a communication between the shareholder and the company’s management, and not necessarily as clear, actionable directions from the Minister in his or her capacity as Minister. Directives issuing from the Minister as Minister should be seen as non-discretionary in a way that instructions from the Minister as shareholder are not. In the one case, where the Minister issues a directive as Minister, recovery of costs should be the generally expected outcome, provided the spending was incurred prudently. In the other case, a more detailed and searching rationale may be needed to support recovery of costs through rates. In this context, this utility ought not to be treated any differently than any other utility receiving instructions from its shareholders.

Hydro One has proposed to return to its customers a net amount of $7.4 million arising from the disposition of all of the accounts. An amount of $12.5 million is proposed to be returned over 12 months, and $5.1 million is proposed to be collected over 24 months. On a net basis, Hydro One has proposed to rebate approximately $10 million to its customers in 2011, and collect $2.6 million from its customers in 2012. The reason for this proposed pattern of disposition is stated to be to provide maximum rate mitigation in 2011.

BOMA/LPMA and VECC are opposed to the 24 month disposition period for the balances to be collected from customers. Both intervenors submitted that Hydro One should return the net amount of $7.4 million over a 12 month period in 2011. This approach would provide rate mitigation in 2011, when the rate increase is larger.

The Board agrees with the intervenors, and finds it preferable to dispose of the balances in these accounts over a 12-month period in 2011 rather than return a larger amount to customers in 2011, only to recover some portion of it in 2012.

Proposed New Accounts and Continuation of Accounts

Hydro One requested approval to continue or establish new deferral accounts for the following costs:

1. Impact for Changes in IFRS Account (2012 only)
2. IFRS – Gains and Losses Account (2012 only)
3. IFRS Incremental Transition Costs Account
4. Pension Cost Differential Account
5. Long-term Project Development OM&A Account
6. Tax Rate Changes Account
7. OEB Cost Differential Account

IFRS Related Accounts

The new variance account proposed for Impact for Changes in IFRS for 2012 is for recording the aggregate impact on the 2012 revenue requirement resulting from any changes to existing IFRS standards or changes in the interpretation of such standards from what was in place at the date of Hydro One’s application. CCC and BOMA/LPMA accepted the establishment of this account, as did Board staff. SEC recommended that the Board deny approval to establish the new deferral and variance accounts proposed by the Applicant.

Hydro One pointed out that an identical account was approved by the Board in Hydro One’s recent distribution rate case, EB-2009-0096.

Hydro One proposed to establish IFRS – Gains and Losses Account for 2012 to record gains and losses on asset sales and losses resulting from premature asset retirements. The recorded amounts would be subject to Board review prior to disposition. SEC was not in favour of establishing this account. CCC and VECC, and Board staff had no objection to the establishment of this account. However, VECC noted that the account should also include a depreciation credit that would be calculated based on the amount of depreciation in approved revenue requirement that will not be incurred as a result of premature retirement of an asset. Hydro One, in its reply submission, agreed that the account should be credited for any depreciation expense in rates that will not be incurred as a result of premature assets retirements.

Board Findings

The Board accepts Hydro One's proposal and approves the establishment of the two new IFRS related accounts - Impact for Changes in IFRS Account; and IFRS – Gains and Losses Account.

The Impact for Changes in IFRS Account is approved to record the impact on revenue requirement of changes in IFRS arising between those IFRS standards in force at the date of the company's application and those in force at the time of their next application, i.e. IFRS to IFRS changes. The Board considers it reasonable that Hydro One be allowed to record the effects from changes that might arise under IFRS after the date of their application for consideration in a future proceeding. This account is not for use in recording differences between Canadian generally accepted accounting principles and IFRS.

IFRS – Gains and Losses Account is approved as proposed by Hydro One, including the depreciation credit suggested by VECC.

The Board also approves the continuation of the IFRS Incremental Transition Costs Account proposed by Hydro One. No party objected to Hydro One's request to continue this account. It had been authorized previously in EB-2009-0096 by the Board.

OEB Cost Differential Account

With respect to OEB Cost Differential Account, Board staff submitted that this account was originally created for electricity distributors through Article 220 of the Accounting Procedures Handbook as follows:

> "This account shall be used to record the difference between OEB costs assessments invoiced to the distributor for the Board's 2004/05 and 2005/06 (up to April 30, 2006) fiscal years and OEB costs assessments previously included in the distributor's rates."

The account was closed to new principal entries after April 30, 2006 as the distributors' revenue requirements included amounts for Board cost assessments beginning in 2006.

The evidence on the record[6] indicates that Hydro One's revenue requirement also includes an amount for OEB cost assessments. Intervenors CMA, CCC, SEC, and VECC made submissions against granting this account to Hydro One.

Hydro One, in its reply submission, stated that its request to continue to track the differential between forecast and actual annual OEB cost assessment in this account for 2011 and 2012 is consistent with the existing account that was approved by the Board in the last transmission rate proceeding, and a similar account was approved by the Board in Hydro One's last distribution rate proceeding.

Board Findings

The Board finds that Hydro One is not justified in continuing to use this account, since its revenue requirement already includes an amount for OEB cost assessments. The original purpose of the account was to assist utilities that were unable to include a forecast of the Board's increased assessed costs in their rate applications because they arose in years for which rates were already set, not as an ongoing variance account. Accordingly the OEB Cost Differential Account should be closed.

Other accounts

There was no opposition to the continuation of the Pension Cost Differential Account, the Long-term Project Development OM&A Account, and the Tax Rate Changes Account. The Board approves continuation of these accounts.

Proposed Discontinuance of Accounts

Hydro One, in its pre-filed evidence, asked to discontinue the following 3 variance accounts:

- Export Service Credit Revenue
- External Secondary Land Use Revenue
- External Station Maintenance and E&CS Revenue

CME, CCC, BOMA/LPMA & AMPCO, SEC, and VECC, all argued against Hydro One's proposal to discontinue the use of Export Service Credit Revenue, External Secondary Land Use Revenue and External Station Maintenance and E&CS Revenue variance accounts, as did Board staff.

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[6] Exhibit C1/Tab2/Schedule 7, page 18

Board staff submitted that Hydro One had a total credit of $12.5 million in these accounts as of December 31, 2009, and submits that it would be premature to discontinue the use of these accounts at this time until it is proven that the variances are sufficiently immaterial to cease tracking them in the variance accounts.

Hydro One, in its reply submission, stated that it is agreeable that the Board approve continuation of these three external revenue accounts.

Board Findings

The Board approves the continuation of the Export Service Credit Revenue, External Secondary Land Use Revenue and External Station Maintenance and E&CS Revenue variance accounts for the test years.

International Financial Reporting Standards (IFRS)

Hydro One used Canadian Generally Accepted Accounting Principles (CGAAP) for the 2011 filing. This is consistent with the July 28, 2009 *Report of the Board on Transition to IFRS* (EB-2008-0408) ("Board IFRS Report"). For 2012, Hydro One filed its submission as a Modified IFRS (MIFRS) submission, using the assumption that MIFRS equals CGAAP, with two significant exceptions, which Hydro One has asked the Board to approve. These exceptions are:

- That Hydro One be allowed to continue to capitalize, for regulatory purposes, overhead expenditures such as training, Common Corporate Functions and Services ("CCF&S") and Line supervision which would not be capitalized using IFRS but which Hydro One states are causally associated with the construction and bringing into service of new capital works; and

- That Hydro One be permitted to establish a new variance account to record gains and losses on tangible and intangible asset sales or losses which result from premature retirements.

Elsewhere in this Decision, the Board has directed the establishment of the variance account IFRS – Gains and Losses Account.

Hydro One wishes to continue to capitalize overhead expenditures associated with the construction and bringing into service of new capital works such as training, CCF&S and line supervision that would not otherwise be capitalized under IFRS. The specific proposal is for such costs to be capitalized for regulatory purposes as a continuation of existing practices.

The Board IFRS Report addressed the topic of accounting for overhead costs in the cost of new capital work effective January 1, 2011 in Issue 3.3. The report stated the following:

> "3.3 The Board will require utilities to adhere to IFRS capitalization accounting requirements for rate making and regulatory reporting purposes after the date of adoption of IFRS… Revenue requirement impacts of any change in capitalization policy must be specifically and separately quantified."

The Board issued a letter on February 24, 2010, clarifying and reinforcing the capitalization policy stated in the Board IFRS Report. The letter states:

> "This letter is to clarify that the Board's position on Issue 3.3 from the Board IFRS Report applies independently of what the approval outcome of the IASB draft standard may be, as follows:
>
> - As stated in the Board IFRS Report at Issue 3.3, the Board is requiringfull compliance with IFRS requirements (e.g. IAS16) as applicable to non-regulated enterprises and only where the Board authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable.

Section 7 of the Board IFRS Report states that all rate impacts should be considered in aggregate, and then any mitigation mechanisms should be addressed, if required.

> "7.2 Rate impacts should be considered in aggregate to determine the significance of the cumulative effect. [Distributors] must provide specific information regarding the individual cost drivers making up the aggregate impact.
>
> 7.3 Utilities must provide a proposal for a rate mitigation mechanism if the impact is material and mitigation appears to be required."

Hydro One did not provide a response to the interrogatory question regarding rate impact mitigation actions.

Hydro One, in its reply submission, discussed the following options for the Board to consider:

- To reflect the increased revenue requirement of $200M in rates beginning when it adopts MIFRS in 2012,

- Approve Hydro One's requested costing exception,
- Use a deferral account, and
- Include the $200M estimate of the impact in 2012 rates, with the difference between the forecast and actual revenue requirement impact tracked in a variance account for 2012.

Hydro One's witness Mr. Fraser stated the aggregate impact of adopting IFRS in 2012 without the exceptions to be an annual increase in revenue requirement of approximately $200 million, all of which relates to the overhead capitalization issue. In response to a Board Staff interrogatory, Hydro One stated that the overhead at issue for capitalization is $152 million. In relation to OM&A, if the amount of overhead not permitted in capital were charged to OM&A as suggested by Hydro One as an alternative, the effect would be to increase OM&A from the requested $450 million to $602 million.

The increase in revenue requirement that Hydro One has otherwise applied for is 9.8% from 2011 to 2012, presuming that its current overhead policy continues. Mr. Fraser estimated that the effect of the increase in transmission revenue requirement from 2011 to 2012 would be about 24% if the Board did not grant Hydro One's request and took the full amount of the accounting change into OM&A. Hydro One also estimated that the transmission charge represents about 7.5% of the total bill.

SEC supported Hydro One's request that the Board approve Hydro One's requested costing exception to the Board's stated policy due to concerns about rate impact. No other intervenors commented on this issue.

Board staff argued that Hydro One's request for a costing exception should not be granted. Board staff submitted that Hydro One should be required to adopt the more restrictive overhead capitalization policy provided under IFRS and address any rate impact concerns through other means. Board staff submitted that additional business measures beyond the accounting reclassification of the overhead costs at issue should be explored by Hydro One. Hydro One stated that, in general, business measures will not change the substantive relationship between the indirect activity and the capital work, so no mitigation of the issue is achieved.

Board staff expressed concern that the cost drivers for allocation of overhead costs are based on the content of the capital work program and therefore may concentrate more on allocation than on whether increases in the actual expenditures on common costs are fully justified.

Board Findings

The Board notes that Hydro One is essentially asking the Board for an exception to its stated policy regarding the capitalization of overhead costs associated with self-constructed assets. This request contravenes a purpose of the Board's policy: to bring consistency in overhead capitalization policy among the utilities rate-regulated by the Board.

The Board also notes the following uncertainties:

- Hydro One has stated in its reply submission that the company will continue in discussion with its external auditors to work towards mitigating the impact by justifying the maximum allowable classification of expenditures as capital.

- The amount of $152 million for 2012 is the amount Hydro One states to be at issue regarding potential exclusion from amounts capitalized to the cost of self-constructed assets. There remains an amount in capital expenditures of directly attributable overhead still considered appropriate under IFRS to capitalize. Hydro One stated that the planned capital spending for 2012 is $1,178 million. Exclusion of an amount of $152 million attributable to training, CCF&S and Line Supervision appears to be such a large proportion as to raise questions about whether overhead capitalization, while supported by external studies may, nonetheless, be at the high end of accepted practice under Canadian GAAP. This can be seen by recognizing that the remaining $1,026 million capital expenditures for 2012 continues to include material, labour, third party contract work, carrying charges during construction and still also includes an amount of directly attributable overhead permitted under IFRS.

- The capital expenditures for 2012 in this proceeding reflect a forecast three years in the future. Also, from audited financial statements provided in the proceeding, the actual capital expenditures have been increasing quickly, doubling from $560 million in 2007 to the proposed amount for 2012. This increase in spending may be justified, but the Board notes that with three years forecast and with a high rate of spending increase, there is risk of inaccuracy. The Board agrees with Board staff and SEC that it does not follow that the amounts of overhead capitalized should increase proportionately in the face of a doubling of the capital program. The Board is concerned about whether the apparently large amounts of overhead not eligible for capitalization under IFRS are accurately forecast.

- Board staff submitted that Hydro One had not identified the business measures that it had taken to mitigate the overhead cost reclassification impact. Hydro One in reply stated that, "In general, business measures will not change the substantive relationship between the indirect activity and the capital work, so no mitigation of the issue is achieved." As a result the Board is not assured that all possible means of mitigation beyond accepting the reclassification have been explored by Hydro One.

The Board has some sympathy for the position that Hydro One finds itself in regarding this issue. In particular, the Board notes that Hydro One is proposing to continue its existing policy for rate-setting purposes as a way to avoid having to mitigate the impact of adopting alternative policy, an approach the Board considers to be worthy and considerate of ratepayers. Hydro One acknowledges that its request for the costing exemption is based entirely on customer rate impact considerations.

The Board accepts Hydro One's observation that many utilities in Ontario have other areas of offsetting impact not available to Hydro One, particularly with regard to adjustments arising from assuming responsibility for determining asset service lives based on depreciation studies by external experts. Hydro One has already assumed this responsibility and adopted service lives based on studies by external experts. Thus for Hydro One Transmission the circumstances arising from the transition to IFRS are focused on the overhead capitalization issue.

The Board is mindful of Hydro One's concern that the amount at issue will recur each year such that the company strongly opposes the use of a deferral account since a deferral for this matter for new amounts arising each year will be required and the problem will not be resolved. The Board therefore rejects Board staff's recommendation of a deferral account as a means of addressing this problem.

The Board concludes that Hydro One should adopt IFRS accounting for overhead capitalized as part of the cost of self-constructed assets, for regulatory accounting purposes, and include an additional $200 million in revenue requirement. The Board recognizes that this impact is significant. However, it will occur only in one year. The Board also recognizes that from the consumer's perspective the transmission charge represents only about 7.5% of the total bill and in the broader rate-setting environment a one-time adjustment will resolve the issue.

The Board is concerned that Hydro One not continue with accounting policies that are at the extreme end of what would otherwise be considered generally accepted under Canadian GAAP, and which are not accepted under IFRS. The Board considers the IFRS capitalization policies to be an appropriate evolution in the treatment of this issue from a regulatory point of view.

The Board shares the concern expressed by Board staff that cost drivers for allocation of overhead costs may concentrate more on allocation than on whether increases in the actual expenditures on common costs are fully justified. With respect to mitigation through adjustment of business measures, the Board does not see merit in artificially modifying business processes to mitigate impacts. However, the Board does expect that Hydro One will review its business processes in the normal course and make all reasonable adjustments to mitigate rate impacts.

In addition, and given that the resolution of the uncertainties discussed above may create a potential reduction of the amount ultimately included in OM&A, the Board requires Hydro One to create a variance account to capture any variance from the $200 million revenue requirement impact attributed to this issue. Variances will be considered for disposition in a future proceeding.

NETWORK CHARGE DETERMINANT "HIGH 5"

In this proceeding, Hydro One proposed to maintain the existing Network charge determinant, which has remained unchanged since implementation of the Board's rate order in RP-1999-0044. This Network charge is on actual kW per delivery point, measured monthly, for one hour, and is the higher of the load at the hour of system peak or 85% of the non-coincident peak. The latter amount is measured only during the broad peak period 7:00 am to 7:00 pm weekdays.

AMPCO proposed changes to the Network charge determinant in Hydro One's EB-2006-0501 transmission rates case, in the form of eliminating non-coincident demand during the 12-hour week-day peak period, and decreasing the number of months during which the coincident peak would be included. The Board did not accept the proposed changes.

In the next Hydro One transmission rates case (EB-2008-0272), AMPCO again proposed a change which is now known as the "High 5" charge determinant.

The High 5 proposal differs in two fundamental ways from the status quo.

First, it is based on coincident demand during a single hour on five different days – there is no reference to month and no reference to non-coincident demand. Rather, the charge determinant is the demand at each delivery point coincident with the highest hourly system load on each of the five days with the highest peak load.

Second, the charge in a given year is based on the delivery point's proportion of total coincident demand during the previous year, so the monthly Network charge is a constant amount for each month during the year.

The Board did not accept the High 5 proposal in EB-2008-0272, but directed Hydro One to conduct an analysis of the proposal, together with a plan for implementation that could be used in the event that the High 5 charge determinant, or a similar proposal, might be ordered in the future.

To that end, in this proceeding, Hydro One filed a study prepared by Power Advisory Inc. (Exhibit H1/Tab 3/Schedule 1, Attachment 1), and also provided its comments on implementation matters (Exhibit H1/Tab 3/Schedule 1, section 4.1).

2011-12 rate years

In addition to AMPCO, CME supported the High 5 proposal. Hydro One, Board staff and all other intervenors were opposed to implementing High 5 during the period covered by this application.

AMPCO submitted that peak-load pricing promotes efficiency in public utility situations such as Hydro One's current application. VECC submitted that this generalization is too broad, and that the High 5 proposal may not result in efficient investment in transmission Network capacity because there are relatively few hours involved in the High 5 structure compared to the factors that currently drive Hydro One transmission costs.

In support of High 5, AMPCO submitted that the concept promotes efficiency in transmission by reducing or delaying the need for Network reinforcement, and in the commodity market by replacing consumption during hours of highest production cost and losses with lower cost consumption.

The Power Advisory Report filed by Hydro One concluded that the High 5 proposal does little to promote efficiency over the long run because most Network capital expenditures for the next few years are not being driven by peak load. In other words, there is little investment deferred even if load were decreased during the High 5 hours (plus a small number of additional hours when consumers might decrease their load in case it turned out to be one of the High 5 hours).

VECC suggested that the cost of shifting load away from the High 5 hours could decrease overall efficiency, as the private costs incurred by customers would exceed any savings to the system as a whole. Further, VECC submitted that, as a result of High 5 being such a small number of hours, load shifted away from those hours may fall onto hours in which the system load is still relatively high. VECC suggested two implications if this were the case:

> First, AMPCO overstated the likely savings in the cost of producing the electricity commodity, as measured by HOEP, and
>
> Second, the shifted load may add to regional peak loads and could require system reinforcement where the Network has peak hours that have been shown to be outside the overall peak if narrowly defined.

VECC submitted that adding a transmission cost incentive for load shifting, on top of the incentive already given by the HOEP, may decrease overall efficiency by incenting load shifting beyond the economic level. VECC and SEC argued that transmission rate design should not be complicated by consideration of the commodity market, and that any alleged inefficiency in the production of electricity is or should be seen to be within the commodity market.

CCC noted that in the previous EB-2006-0501 Decision, the Board placed the onus on AMPCO to show that any change is an improvement over the status quo. While acknowledging that the evidence provided in the present proceeding is more comprehensive than previously, CCC submitted that there is still not a convincing argument that High 5 is an improvement over the existing method. SEC and VECC also submitted that there is no compelling evidence for change.

Board staff filed a summary of a proposed government regulation concerning the allocation of Global Adjustment costs. The proposed regulation would use an allocation that is very similar to the High 5 allocation of Network costs proposed by AMPCO. The Power Advisory witnesses testified (TR Vol. 8, p. 28) that the regulation, if enacted, would likely create a stronger incentive to shift load away from the High 5 hours than the Network charge would. An estimate of the combined effect requires an even larger extrapolation from actual observation, which creates additional uncertainty.

Fairness

AMPCO submitted that High 5 is a fair rate design because it is a more straightforward method of peak-load pricing and as such, it reflects cost causation with respect to Network facilities. AMPCO submitted that the High 5 structure is consistent with the objective of fairness, because consumers that incur private costs in order to be able to shift load are compensated for this cost through lower Network charges.

Hydro One noted that a number of alternatives were considered in the EB-2006-0501 proceeding and maintained that the existing method is a fair balancing of cost among the various consumers.

Hydro One also noted that there would be unequal treatment between customers connected to transmission delivery points and similar customers connected at a lower voltage to distribution lines. BOMA/LPMA, CCC, SEC and VECC all submitted that the High 5 structure is contrary to principles of fairness because it is not apparent how the incentive could be extended to the majority of consumers.

AMPCO also submitted that peak load pricing is fair because it reflects cost causation with respect to transmission investment requirements. Board staff and CCC submitted that the principle of fairness depends on whether the issue is cost causation of new Network facilities that might be built to accommodate future loads, or recovery of the cost of facilities that are already in place and were put there to accommodate now-existing load. Staff and CCC submitted that the objective in the present situation is primarily a fair recovery of the cost of the existing system, which was also a conclusion in the Power Advisory study.

Board Findings

While Hydro One is financially indifferent as to the outcome of this issue, for all other participants in the transmission market this issue has important financial implications.

Simply put, adoption of the High 5 charge determinant would shift cost responsibility from industrial users who are able to organize production schedules away from peak periods to the remaining customers of the transmission system. For those able to make those schedule changes, the differences will be very significant. However, what these customers do not pay in transmission rates must be made up for by all other transmission system users whether they be industrial, commercial, or residential.

The fundamental rationale for the adoption of the High 5 proposal is that it is said to address the primary cost driver for transmission system maintenance and development, which is peak period use. The proposition is that to the extent that peak usage can be minimized by shifting production schedules away from peak periods, the highest costs for system maintenance and expansion can be avoided. This, it is suggested, is a system benefit, not merely a benefit to those capable of shifting schedules.

While this rationale may be more relevant in other transmission systems, at the current time, and for the reasonably foreseeable future, it is not particularly germane to the Ontario transmission environment. Now, and for a considerable period to come, the driving force behind transmission system costs for maintenance and expansion is the renovation of the system to accommodate challenging amounts of renewable generation. Prior to the advent of an aggressive approach from the Ontario government to enable renewable generation, system peak might well be identified as the primary driver of system cost. However, that is no longer the case, and it will not be the case for some time to come.

This circumstance is one important factor in considering the advisability of adopting the High 5 methodology.

In addition, the Board is concerned that a methodology that emphasizes such a small sample, that is, five peak periods in the course of the year, could lead to anomalous and unintended results. As VECC and the Power Advisory Report contend, emphasis on the five highest hours does not adequately take into account times of system usage falling just below the five-hour levels. Very considerable system resources should be expected to be associated with a number of hours falling just outside of the top five. This top-heavy emphasis on a very small sample seems to the Board to be unwarranted, and inconsistent with the underpinning rationale of the High 5 methodology, which is that users at the highest peak periods ought to bear the most cost. The High 5 proposal restricts that principle to an inordinately small sample.

In addition, the Board is concerned that it is only a very select group of industrial users who could take advantage of the High 5 methodology, leaving all the rest to pay the shortfall. For many industrial operations, such elasticity in production schedules is simply not available.

The Board is also interested in the regulation which allocates the Global Adjustment according to a High 5 methodology. The Global Adjustment, which is partly driven by the expansion of the renewable generation fleet, represents a very considerable proportion of the electricity bill for Ontario consumers of all classes. The Ontario government's plan to allocate this significant cost by means of the High 5 methodology should prove to be useful in assessing its potential effect were the methodology to be adopted more broadly as proposed by AMPCO.

For these reasons, the Board will not adopt the High 5 methodology for the purposes of establishing network transmission rates at this time. Given the reasons for rejection of the proposal, it is certainly open to any party to bring this proposal back to the Board at a time when costs associated with peak usage are seen to drive transmission system costs. Also, as noted above, the Board will look with interest on the effects on system usage prompted by the Global Adjustment allocation regulation, which may provide concrete and reliable evidence for the Board to consider in a future proceeding.

EXPORT TRANSMISSION SERVICE (ETS) TARIFF

The ETS rate of $1.00 per MWh has remained unchanged since the implementation of Board Order RP-1999-0044 at the time of market opening, May 1, 2002. The ETS rate has been an issue at previous Hydro One transmission rate applications, and was the subject of a study and report by the IESO filed in this proceeding. In this application, as recommended in the IESO report, Hydro One proposed to continue the ETS rate at $1/MWh for 2011 and 2012.

The IESO retained Charles River Associates (CRA) to do a quantitative analysis of the future effect of several export rate scenarios, with respect to exports and wheel-through volumes, ETS tariff revenue, and the Hourly Ontario Energy Price. The rate scenarios included: continuing with the status quo, no charge and a charge of $5/MWh. No scenarios of a tariff level between $1 and $5/MWh were included. The IESO extended the quantitative analysis of the scenarios, identifying the incidence of costs and benefits amongst consumers and power producers. The IESO also made a qualitative analysis of the scenarios to assess operational effects.

The results of the quantitative analyses indicated that, among the rates considered, the net Ontario benefit would be highest with the $5/MWh rate. This happens to be the scenario with the highest consumer surplus and lowest producer surplus. The IESO did not recommend this rate, citing circumstances that had changed between early 2009 when the study began and August 2009 when it formulated its recommendation.

Among the factors that had changed was an increase in Surplus Baseload Generation (SBG), which occurs when production from baseload resources such as nuclear, wind, non-utility generators and must-run hydro facilities is greater than market demand. With the higher export tariff, SBG levels would increase further because export volume would be lower. In an SBG situation, nuclear units might be dispatched down or off, for example, which would have economic costs not adequately considered in the CRA or IESO analyses.

2011 Rate

Several parties endorsed the recommendation to approve the rate of $1/MWh, along with Hydro One and the IESO. Bruce Power, the Association of Power Producers of Ontario (APPrO) and Hydro Quebec Energy Marketing Inc. recommend that the Board approve continuation of the rate in 2011. Board staff said that it could make no recommendation other than continuation of the status quo, because the evidence does not support any specific rate other than $1/MWh.

The parties recommending a rate higher than $1/MWh in 2011 were CCC, BOMA/LPMA, CME, Pollution Probe, SEC and VECC.

SEC submitted that the evidence before the Board supports the rate of $5/MWh, based on the CRA study, and noted that the status quo had never had an empirical basis. SEC recommended implementation of the $5/MWh rate in 2011 or $3/MWh if the Board was not prepared to move to $5/MWh in a single step.

Pollution Probe also recommended implementation of $5/MWh in 2011.

CCC and BOMA/LPMA recommend $2/MWh in 2011, though as noted below they differ in their recommendation for 2012.

VECC recommended that, at a minimum, the ETS tariff should be increased by the same percentage as the Network charge, which would be $1.24/MWh in 2011. VECC submitted that the Board should give serious consideration to a time-of-use export tariff, beginning in 2011 or 2012, and recommended that the rates be $2/MWh in the peak period and $1/MWh in the off-peak period. In support of this recommendation, VECC pointed out that the SBG conditions occur primarily in the off-peak and would not be exacerbated by the higher rate during the peak period. VECC went on to submit that the status quo, by being lower than the rates in other jurisdictions, may have reduced the incentive of neighbouring jurisdictions to reciprocate with lower tariffs of their own. CME adopted the VECC submission.

2012 Rate

With regard to the ETS rate to be set for 2012, the parties that supported the continuation of the rate at $1/MWh for 2011 recommended the same in 2012.

SEC recommended that the rate should remain unchanged from 2011 at $5/MWh, or failing that, $3/MWh. Pollution Probe did not make a recommendation for 2012 separate from its recommendation of $5/MWh in 2011. CCC recommended continuing at the rate at $2/MWh in 2012. BOMA/LPMA recommend $3/MWh, provided that the IESO did not identify issues or concerns that would have arisen from its experience with the higher rate during 2011.

VECC did not make a separate recommendation for 2012 concerning the time-of-use tariff but recommended that, again as a minimum, the ETS rate should increase by the same percentage as the proposed Network charge to $1.33/MWh.

Further Study of the ETS tariff

Board staff submitted that the IESO should analyze the market again, comparable to the CRA study but updated to reflect the considerations that led the IESO to recommend the status quo instead of the conclusions that were filed with this application. Staff submitted that the Board should be given a wider range of alternatives for the ETS, supported by quantitative evidence.

The IESO suggested that it may be appropriate to study the matter of the ETS tariff at a future time, after the effects of recent incentives for renewable energy generation will have been realized and operational experience gained by the IESO.

Except for Board staff, the parties that supported continuation of the current rate in 2011 did not make any recommendation for further study. Several parties that recommended an immediate increase in the rate also submitted that further study is not required.

Board staff, CCC, VECC, and CME submitted that the IESO should be required to submit the study in time for the next transmission rate application. SEC added that, if the study is not submitted in time for the next proceeding, the 2013 ETS rate should rise to $5/MWh (if the Board had not already taken SEC's recommendation to do so in 2011).

Several parties submitted that it would not be useful to simply update load forecast and cost data into the methodology already employed in the current study.

Bruce Power and APPrO pointed out that one of the main assumptions in the previous study – that consumer surplus accruing to Ontario consumers will be larger if export levels and the commodity market price are lower – is no longer relevant. Because the Global Adjustment runs counter to the commodity market price, the effective price paid by Ontario consumers is nearly the same in all scenarios.

Pollution Probe and SEC submitted that the effect of a higher export rate is not necessarily to lower exports, because power producers can bid correspondingly lower prices into the electricity spot market in order to avoid SBG situations.

The IESO submitted that it is not the appropriate entity to do a rate design study. However, it appeared to not dispute that it would be the appropriate body to update the CRA and its own study if such an update is to be done. VECC submitted that Hydro One should assume the lead role, because it has the responsibility to submit a comprehensive rate proposal, including an appropriate export rate. Hydro One disagreed with this position. Board staff submitted that Hydro One should become more involved in formulating the recommendations, while submitting that the IESO should retain the lead role.

Bruce Power and APPrO submitted that the Network was built to serve domestic load, not export load. In this view, cost causation is an important objective, and power producers are not responsible for Network cost. In any case, equal rates across all users are not necessarily synonymous with fairness.

APPrO also submitted that the Board's statutory objectives include economic efficiency in generation as well as transmission. Consideration of economic efficiency in generation would include the cost to power producers of adapting to SBG situations.

Bruce Power and APPrO argued that the Board should defer to the expertise of the IESO in the matter of the ETS rate. By recommending rates for 2011 other than the rate recommended by the IESO, a number of parties are suggesting that the Board should not defer to that expertise. VECC submitted that the IESO's input should be solicited on matters affecting system operation, but that Hydro One is accountable in what should be viewed as a conventional rate design study. Further, VECC suggested that the IESO's proposed schedule for updated information and recommendations is an unacceptable and unproductive delay.

Board Findings

The Board's analysis of this issue begins with the observation that the original one dollar ETS rate was established initially as a placeholder, and was not the product of an objective, principled, or programmatic study. It therefore cannot be considered to have any particular precedential value. The issue is a long-standing one, and until very recently it has not been subjected to any form of genuine analytical review. Having said that, there is little virtue in replacing one placeholder with another in the absence of evidence supporting the new value.

VECC proposes that the establishment of the ETS be predicated on the rate-making methodology and outcomes for the rest of the transmission system. While this is an attractive symmetry, there is simply no basis upon which to conclude that conventional rate-making practice is genuinely relevant to the establishment of this export rate.

The CRA study is of some assistance. While its sponsors abandoned its recommendations in light of current market conditions, particularly the higher incidence of surplus baseload generation, it is the only programmatic study that exists in this record.

That study concluded that an increase in the ETS from $1 to $5 optimized the net Ontario benefit. The five dollar rate, if adopted, would increase the surplus for consumers and correspondingly be expected to decrease the generator's surplus. As noted above, the CRA study did not examine the impact of rates falling between the existing one dollar rate and the five dollar rate.

The Board concludes therefore that the most pressing requirement is that a genuinely comprehensive study be undertaken to identify a range of proposed rates and the pros and cons associated with each proposed rate in time for the next transmission rate application. In the Board's view, the most appropriate party to undertake this study is the IESO. In procuring the study, the IESO should circulate the terms of reference to the Applicant and the intervenors of record in this case with a view to ensuring that the resulting study will provide detailed analysis on the issues.

This review of the terms of reference is not intended to be a strategic negotiation, but rather a technical exercise to ensure that the scope of the project is sufficiently broad and well-defined to ensure a useful and appropriate outcome. Work on this study should begin soon, to ensure completion well in advance of the time for the filing of the next transmission rates application by Hydro One.

In the interim, the Board must consider whether continuation of the one dollar placeholder is appropriate or whether some interim change to the approved rate should be made pending the development of a principle-based new rate.

The CRA study did not examine any of the rate level options falling between the one dollar placeholder and the five dollar rate recommendation which was ultimately abandoned by IESO for the reasons cited above.

It is the Board's view that the CRA study is informative to the extent that it considered the higher rate to result in a higher net Ontario benefit. While the Board respects IESO’s reticence to advocate the higher rate, it does appear as though some level between one dollar and five dollars is directionally advisable.

Accordingly, the Board will direct that a change be made to the ETS rate for 2011 and 2012, increasing the rate to two dollars per MWh. In making this change the Board seeks to recognize the directional preference of the CRA study, and the absence of any particular analytical underpinning for the current rate. Subsequent panels assessing the level of this rate should not, however regard this new rate as having any particular precedential value. It is the Board's view that the new rate has more analytical support than the status quo, but that in order to arrive at a genuinely robust and valid rate, more study is required.

TOTAL BILL IMPACTS

One issue that was raised over the course of this proceeding was whether the Board should consider total bill impacts affecting Hydro One transmission customers and not just the bill impacts associated with this specific transmission rates application.

In support of the proposition that the Board should take the broader view, on August 26, 2010 CME filed evidence prepared by Bruce Sharp of Aegent Energy Advisors Inc. entitled <u>Ontario Electricity Total Bill Impact Analysis, August 2011 to July 2015</u>. This analysis included a forecast of the impacts of a number of factors other than transmission rates, including the price of the commodity, taxation effects, such as the Harmonized Sales Tax, anticipated increases in distribution rates, the advent of Time of Use (TOU) pricing, and expected government initiatives.

The analysis concluded that non-residential electricity costs would increase at an annual compound rate of 8.0 to 10.4 percent (depending on usage levels) from August 2010 to July 2015. For residential customers, electricity costs would increase at an annual compound rate of 6.7 to 8.0 percent (depending on usage levels) over the same time period. It is common ground that increases of this magnitude, if realized, would be quite significant for both residential and non-residential customers.

In response to a Board staff interrogatory, CME provided additional background to the evidence including how it proposed to use the evidence in this proceeding. CME stated that,

> "Having regard to the Board's obligation under the *Ontario Energy Board Act, 1998* (the *"OEB Act"*) to protect consumers with respect to electricity prices when carrying out its responsibilities under the *Act*, a consideration by the Board of evidence of the total bill impacts customers are experiencing and facing is mandatory."

In its argument-in-chief, Hydro One indicated that it did consider rate impacts in developing its rate proposals but did not expressly take into account extraneous cost pressures which are beyond its control. Hydro One stressed that it does not have any particular ability to take those costs into account, even if it were able to estimate them and even if it was thought appropriate to do so.

Hydro One argued that its paramount duty is to maintain and develop a safe, reliable transmission system, determining what investments are necessary to achieve the safest, most efficient and most reliable transmission system, now and in the future. Hydro One maintained that the current rate proposal, if approved, would enable Hydro One to achieve those objectives.

Hydro One submitted that it made no sense to reduce the needed funding to Hydro One for its transmission network because of the overall impact of a host of factors beyond its control. Hydro One's proposal in this case is an essential link in the chain of supply and delivery of electricity for the Province and it should not be curtailed or prevented from doing its job because of external cost pressures arising from other factors unrelated to the transmission of electricity.

CME took the lead on this issue in filing evidence as noted above. After reviewing the pricing pressures outlined in the Aegent evidence, CME submitted that the overall electricity price increases customers are likely to face over the course of Hydro One's five year planning cycle are a critical consideration when determining the overall reasonableness of the revenue requirement amounts Hydro One is asking the Board to approve.

CME also submitted that when exercising its rate-making jurisdiction under the OEB Act, the Board should give a particularly high priority to its statutory objective of protecting consumers with respect to electricity price increases. In its view, this is especially important during a period where significant overall price increases are anticipated.

CME acknowledged the Board's October 27, 2010 letter outlining three policy initiatives effecting its rate-making practice, designed to manage the pace or rate of bill increases for consumers. However, CME still emphasized that the Board's plan to proceed with these initiatives should not detract from its duty to discharge its statutory obligation in this case, and in every other rates case.

CME also argued that:

- Government policy does not override the Board's obligation to approve revenue requirements and resulting rates for Hydro One that are just and reasonable and in accordance with the Board's obligation to protect consumers with respect to electricity price increases.

- Government policy should not trump the Board's consideration of matters pertaining to economic feasibility. As an independent economic regulator, mandated by statute to carry out its responsibilities so as to protect the overall public interest, the Board should adopt a guarded approach when evaluating the utility spending implications of such policies.

- Government directives made to Hydro One in its capacity as the utility owner, stand on no higher footing than directives Enbridge Inc., the parent of Enbridge Gas Distribution Inc., might provide to its utility, or that Spectra Energy, the parent of Union Gas Limited, might provide to Union. The spending implications of such directives stand to be carefully scrutinized by the regulator for reasonableness. Formal or informal directives a utility receives from its

> Government owner do not preclude the Board from considering matters pertaining to the economic feasibility and prudence of the outcomes of such directives. The Board is not obliged to approve Hydro One's spending plans because they stem from directives it has received from its owner.

CME submitted that the applied-for revenue requirement should be reduced in one or more of the following areas:

(a) Approval of reduced Operation, Maintenance and Administration expense envelopes for 2011 and 2012;

(b) Approval of reduced Capital Expenditure envelopes for 2011 and 2012; and/or

(c) Approval of a reduction in Equity Return and related taxes in 2011 and 2012 to the extent that system safety and integrity is not compromised.

CME argued that if Hydro One's owner is sincerely concerned about the electricity price increases consumers are facing, then it should readily waive the amount of investment return that is not needed to support Hydro One's utility-related activities such as the dividends and related taxes Hydro One is planning to flow through to its owner in 2011 and 2012. CME maintained that the notion argued by Hydro One that temporarily reducing the equity return Hydro One realizes from its ratepayers requires taxpayers to subsidize ratepayers, lacks merit. CME submitted that by allowing Hydro One's owner to recover more than the actual costs of capital it incurs for utility purposes, ratepayers are subsidizing social programs.

Simply put, CME's submission is that in the significant electricity price increase environment that currently prevails, the appropriate regulatory response to Hydro One's application is for the Board to approve revenue requirement envelopes for 2011 and 2012 that reflect further reductions in the OM&A and Capital Expenditure envelopes of the types suggested by Board staff and other intervenors, along with a temporary disallowance of equity return and related taxes not needed to maintain system safety and integrity. CME provided a confidential schedule to their argument containing its estimates of these dividend and related tax amounts.

CCC focused its submissions on the Total Bill Impact on a decision of the Court of Appeal for Ontario in the case of *Toronto Hydro-Electric System Limited v. Ontario Energy Board*.

In that decision, the Court of Appeal made the following observation:

> The principles that govern a regulated utility that operates as a monopoly differ from those that apply to private sector companies, which operate in a competitive market. The directors and officers of

> unregulated companies have a fiduciary obligation to act in the best interests of the company (which is often interpreted to mean in the best interests of the shareholders) while a regulated utility must operate in a manner that balances the interests of the utility's shareholders against those of its ratepayers. If a utility fails to operate in this way, it is incumbent on the OEB to intervene in order to strike this balance and protect the interests of the ratepayers.[7]

CCC argued that Hydro One did not balance the interests of its shareholders and the interests of its ratepayers. With regard to the cost reductions undertaken by Hydro One in response to ministerial directions, CCC submitted that those reductions were due to the impacts of the EB-2009-0096 distribution decision and the deferral of Green Energy related projects, not made on the Company's own volition to protect the interests of consumers.

In its argument-in-chief, Hydro One stated:

> "The profits earned by the company through its allowed rate of return are, ultimately, paid to the province and are used to support a host of social programs, such as, for example, our school system. If we are to reduce the allowed return because of customer impacts, this implicitly means that the taxpayers of Ontario will be subsidizing the electricity users of Ontario." (Tr., Vol. 11, p. 16)

CCC submitted that the Board should draw three conclusions from this admission.

- Hydro One does not need its requested level of ROE for commercial reasons;
- Hydro One could reduce its ROE without compromising the safety or reliability of its system; and
- Hydro One has chosen to prefer the interests of its shareholder over than of its ratepayers.

In addition, CCC submitted that the projects for which the company does not offer evidence of prudence should not be approved for recovery in rates.

CCC submitted that imperatives for a Green Energy Plan were created by the government through legislation. The Minister, in his capacity as the representative of the shareholder, provided, in the September 21, 2009 letter, the direction to Hydro One to

[7] (*Toronto Hydro-Electric System Limited* v. *Ontario Energy Board*, 2010 ONCA 284, para 50)

begin development work on GE projects. The Minister's direction should be given no greater weight than should the direction of any other shareholder. The projects are to provide transmission links to Green Energy supply sources. The sources of supply have been approved by the OPA.

Hydro One has no role in the decision about whether the supply is required, whether the particular renewable energy source is a reasonable one, and, therefore, whether the overall transmission link is prudent. The overriding obligation of the Board is to approve just and reasonable rates, pursuant to section 78 of the OEB Act. The Board cannot, and should not do that in circumstances where Hydro One cannot provide evidence of the prudence of the overall project.

In summary, CCC submitted that:

1. the Board should find that Hydro One has failed to fulfill its obligation to balance the interests of its shareholder and that of its ratepayers;

2. given Hydro One's failure to balance the interests of its shareholder and its ratepayers, the Board is obligated to do so;

3. in order to strike the appropriate balance, the Board should further reduce Hydro One's revenue requirement to ensure that the Total Bill Impact is minimized to the extent possible;

4. the Board should not approve projects, and the cost consequences of projects, which Hydro One does not direct and for which it has not provided its own, independent evidence of prudence.

VECC supported the arguments of CCC on this issue.

In reply, Hydro One recognized and agreed that the impact upon consumers is an important factor to be considered by the Board. The Board is obligated, pursuant to its mandate in section 1(1) of the *Ontario Energy Board Act,* to protect the interests of consumers with respect to prices. However, the Board's function is also to balance the interests of the electricity system, the utility and the consumer. Hydro One's application must be assessed upon the evidentiary record, and not on matters external to Hydro One which are beyond its control and have no evidentiary basis in the proceeding.

Hydro One submitted it would be contrary to the principles of rate making to artificially suppress rates and curtail necessary capital projects and other programs because there may be other matters, external to Hydro One, which also may impact the overall rates charged to customers. The transmission rate is just one aspect of a customer's total bill.

Hydro One did not suggest that the impacts upon consumers ought to be ignored. Hydro One maintained that it had already adjusted its rate proposal in consideration of customer impact issues. Hydro One mentioned its proposed costing exception to IFRS requirements in order to avoid a $200M increase in revenue requirement and its voluntary absorption of additional pension costs in 2011 and 2012.

Hydro One supported the Board initiatives which will assess how total bill impacts ought to be considered by the Board and other stakeholders in cost of service rate applications. Hydro One indicated that it expects to participate fully in the consultation process and submitted that this generic process is the appropriate venue to address this generic issue, not a specific transmission rates application.

Hydro One concluded by urging the Board to consider the evidence in the case, the specific supporting evidence filed to explain the reasons for the variances and increases. Hydro One urged the Board not to make what it termed to be the arbitrary reductions suggested by Board staff and intervenors.

Board Findings

The Board does not accept the intervenors' arguments with respect to denying Hydro One recovery of its calculated ROE. The cost of capital is a cost element in the revenue requirement determination - not a floating discretionary surplus. What is being suggested here is a kind of collateral challenge which is unsupported by evidence going to the appropriateness of the application of the ROE formula to this utility. If it is the view of the intervenors that the cost of capital determination pursuant to the Board's Cost of Capital Report is inappropriate, they may challenge it, as recognized in the Cost of Capital Report itself. Otherwise there is a presumption that the rate arrived at by the Cost of Capital Report mechanism will be applied to every utility.

The Board recognizes that it must balance consumer impacts with the interests of shareholders and strike a balance between the interests of the electricity system, the utility and the consumer. It is important that in managing the quantum of rate increases and the pace of change, the Board not sacrifice the safety and reliability of the system. Any utility, but perhaps most notably this utility, must first and foremost ensure that its current system is appropriately robust and effective. Enhancements or expansions of the system cannot be undertaken at the expense of core reliability and safety. Elsewhere in this decision the Board has stated that expansions to the system ought to be undertaken only where it can be demonstrated that the projects at issue have been subjected to and emerged from a thoughtful, transparent and inclusive regional planning process. That planning process would necessarily include a detailed financial analysis.

The Board recognizes that Hydro One has suggested ways to reduce bill impacts with its proposals for MIFRS, absorbing the additional pension costs for the test years, reducing dividend payments and various efforts to increase productivity by its staff. However, Hydro One needs to be treated like all other regulated utilities in Ontario, and provided with an equal opportunity to achieve a rate of return on equity, regardless of the identity of its shareholder.

The Board has ordered some reductions in this Decision that will work to reduce the bill impact on customers, based on what the Board heard in evidence and arguments. The Board also notes the October 27, 2010 announcement of its three policy initiatives to review ways of exercising its rate-making jurisdiction to manage the pace or rate of bill increases for consumers. This is the kind of generic forum where this issue, which cuts across various sectors and areas of the electricity pricing equation in Ontario, can also be addressed.

IMPLEMENTATION MATTERS AND COST AWARDS

Implementation

Transmission rates in Ontario have been established on a uniform basis for all transmitters in Ontario since April 30, 2002. The revenue requirements for each of the three rate pools for each of the four transmitters are added to calculate the total transmission revenue requirement for each pool. The totals for each pool are divided by the charge determinant applicable for the pool to derive the uniform transmission rate. The current Ontario Transmission Rate Schedules, effective since January 1, 2010, are shown below.

Service Rate	Monthly Rate ($ per kW)
Network	2.97
Line Connection	0.73
Transformation Connection	1.71

In addition, the Ontario Uniform Transmission Rate schedules include the Export Transmission Service Rate.

The transmission revenues collected by the IESO are allocated by the IESO to each of the four transmitters on the basis of revenue allocators approved by the Board. The revenue allocators are calculated by taking the percentage of the revenue for each transmitter and dividing it by the total combined revenue of all the transmitters. The current Revenue Allocators, effective since January 1, 2010, are shown below.

Transmitter	Network	Line Connection	Transformation Connection
Five Nations Inc.	0.00411	0.00411	0.00411
Canadian Niagara Power Inc.	0.00366	0.00366	0.00366
Great Lakes Power Tx Inc.	0.02758	0.02758	0.02758
Hydro One Networks Inc.	0.96465	0.96465	0.96465
Total	**1.00000**	**1.00000**	**1.00000**

Hydro One applied for a transmission revenue requirement of $1,446 million for the 2011 test year and $1,547 million for the 2012 test year. The Board has made a number of findings that will affect these amounts. The Board's findings will change both the charges for the three pools and the revenue allocators for each of the transmitters.

The Board directs Hydro One to file with the Board and all intervenors of record, a draft exhibit showing the final revenue requirement to reflect the Board's findings in this Decision.

In addition, at the same time, Hydro One shall file an exhibit showing the calculation of the uniform transmission rates, and revenue shares resulting from this Decision. This exhibit should include the most recent approved revenue requirements and pool load forecasts for each of the other Ontario transmitters including the recent decisions for Great Lakes Power Transmission Inc. (EB-2009-0408) and Five Nations Energy Inc. (EB-2009-0387).

Hydro One shall file these exhibits no later than 14 calendar days after the issuance of this Decision. Hydro One should provide a clear explanation of all calculations and assumptions used in deriving the amounts used in these exhibits. Intervenors shall have 7 calendar days to comment on Hydro One's exhibits.

The Board notes that all three of the remaining Ontario transmitters are approved intervenors in this proceeding.

Hydro One should respond as soon as possible to any comments by intervenors, but not later than 7 days after the deadline for comments from intervenors.

If any specific matter has not been dealt with for purposes of drafting the rate order to implement the new rates or dispose of the deferral/variance accounts, Hydro One shall clearly identify these in its filing.

Cost Awards

A number of intervenors were deemed eligible for cost awards in this proceeding. On June 28, 2010, Procedural Order No. 1 was issued with the finding that the following parties were eligible for a cost award: Association of Major Power Consumers in Ontario, Consumers Council of Canada, Canadian Manufacturers and Exporters, Energy Probe, Pollution Probe, School Energy Coalition, Vulnerable Energy Consumers Coalition, Association of Power Producers in Ontario, London Property Management Association, and the Building Owners and Managers Association of the Greater Toronto Area.

A cost awards decision will be issued after the steps set out below are completed.

1. Intervenors eligible for cost awards shall file with the Board and forward to Hydro One their respective cost claims within 35 days from the date of this Decision.

2. Hydro One may file with the Board and forward to intervenors eligible for cost awards any objections to the claimed costs within 40 days from the date of this Decision.

3. Intervenors, whose cost claims have been objected to, may file with the Board and forward to Hydro One any responses to any objections for cost claims within 47 days of the date of this Decision.

Hydro One Networks Inc. shall pay the Board's costs of and incidental to, this proceeding upon receipt of the Board's invoice.

DATED at Toronto, December 23, 2010

ONTARIO ENERGY BOARD

Original Signed By

____
Paul Sommerville
Presiding Member

Original Signed By

____
Ken Quesnelle
Member

Original Signed By

____
Paula Conboy
Member

APPENDIX A

HYDRO ONE NETWORKS INC.
2011 AND 2012 ELECTRICITY TRANSMISSION
REVENUE REQUIREMENT AND RATES

DECISION WITH REASONS

BOARD FILE NO. EB-2010-0002

PROCEDURAL DETAILS
INCLUDING LISTS OF PARTIES AND WITNESSES

DECEMBER 23, 2010

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

THE PROCEEDING

On May 19, 2010 Hydro One Networks Inc. ("Hydro One") filed an application for 2011 and 2012 transmission and revenue requirement and rates. The Board assigned file number EB-2010-0002 to the application and on June 7, 2010, the Board issued a Letter of Direction and Notice of Application to Hydro One Networks Inc.

Hydro One confirmed the that it had fulfilled the service and publishing requirements found in the Letter of Direction when it filed is Service Affidavit with the Board on July 19, 2010.

Hydro One indicated in its Notice that if the application was approved as filed, the resulting increase in the Hydro One Transmission Revenue Requirement would be 15.0% in 2011 and 7.0% in 2012. These increases represent an estimated average increase on total customer bills of 1.2% in 2011 and 0.7% in 2012. For a residential customer consuming 800 kWh per month, the estimated increase on the customer's total monthly bill is $1.39 in 2011 and $1.00 in 2012.

In response to the Notice, the Board received 27 requests for intervenor status, which it approved. The Board also received 13 Letters of Comment from Ontario ratepayers, expressing concern with the proposed rate increases in 2011 and 2012.

The Board issued Procedural Order No.1 on June 28, 2010, establishing the procedural schedule for a number of early events. The Board indicated that it intended to proceed by way of an oral hearing preceded by written interrogatories and a settlement conference. The Board attached a draft issues list to the procedural order and invited submissions on the items on the list from Hydro One and the intervenors for the Board's consideration.

Hydro One brought a motion before the Board on June 16, 2010 requesting an Order severing the issue of the AMPCO proposal to alter the method of determining the transmission network charge, termed the "High 5 Proposal" (Issue 8.1), for review and assessment in a separate generic proceeding. The Board heard this motion July 20, 2010 and denied the motion in an oral decision delivered on that day.

The Board also issued its decision on the draft issues list in the same July 20, 2010 oral decision.

A copy of the decision on the motion is attached as Appendix B and the approved Issues List is attached as Appendix C.

Procedural Order No. 2 was issued on July 21, 2010 with the Board's approved Issues List.

CME brought a motion before the Board on the first day of the oral hearing September 20, 2010 requesting an order requiring Hydro One to produce certain materials provided to the Hydro One Board of Directors and requested in CME Interrogatories 1 and 2. The Board granted the motion in an oral decision on September 20, 2010.

A copy of the decision on the CME motion is attached as Appendix D.

Two intervenors filed evidence before the Board: AMPCO provided evidence on the High 5 charge determinant issue (Exhibit M-1), and CME provided evidence on Total Ontario Electricity Bill Impacts (Exhibit N-1).

A settlement conference for this proceeding was held on September 16, 2010, however no settlement was achieved.

The oral hearing for this proceeding took place on September 20, 21, 23, 24, 27, 28 and October 1, 4, and 5 2010. Hydro One presented oral argument-In-chief on October 7, 2010. The IESO filed its submissions on October 15, 2010. Board staff and intervenor submissions were submitted on October 22, 2010 and November 2, 2010 respectively. Hydro One submitted its reply argument on November 12, 2010.

PARTICIPANTS AND REPRESENTATIVES

A list of participants and their representatives who were active either at the oral hearing or at another stage of the proceeding is shown below. A complete list of intervenors is available at the Board's offices.

Board Counsel and Staff	Jennifer Lea Maureen Helt
	Harold Thiessen Rudra Mukherji
Hydro One Networks Inc.	Don Rogers Anita Varjacic
	Allan Cowan James Malenfant
Society of Energy Professionals	Richard Long

Pollution Probe	Basil Alexander
Consumers Council of Canada	Robert Warren
Canadian Manufacturers and Exporters	Peter Thompson Vince DeRose
Association of Major Power Consumers of Ontario	David Crocker Shelley Grice
Energy Probe Research Foundation	Peter Faye David MacIntosh
School Energy Coalition	Jay Shepherd
Building Owners and Managers Association of the GTA and the London Property Management Association	Randy Aiken
Independent Electricity System Operator	Brian Rivard Carl Burrell
Green Energy Coalition	David Poch
Hydro-Quebec Energy Marketing	Mark Rodger
Association of Power Producers of Ontario and Five Nations Energy Inc.	Richard Long Lucas Thacker
Vulnerable Energy Consumers' Coalition	Michael Buonaguro
Brookfield Energy Marketing Inc.	Charles Keizer
Power Workers' Union	Richard Stephenson Bayu Kidane

WITNESSES

There were 24 witnesses who testified at the oral hearing.

The following Hydro One employees appeared as witnesses:

Bing Young	**Director, Transmission System Development**
Nairn McQueen	Senior Vice-President, Engineering and Construction Services
Peter Gregg	Senior Vice-President, Corporate and Regulatory Affairs
George Juhn	Director, Sustainment Investment Planning, Asset Management
Carmine Marcello	Senior Vice-President, Asset Management
Andrew Spencer	Manager, Sustainment Investment Planning, Asset Management
Paul Tremblay	Director, Network Operating Grid Operations
Debra Vines	Director, Corporate Planning and Regulatory Finance
Keith McDonell	Manager, Human Resources Operations
Tom Goldie	Senior Vice-President, Corporate Services
Mike Winters	Chief Information Officer
Sandy Struthers	Senior Vice-President and Chief Financial Officer
Colin Fraser	Manager, Financial Reporting and Accounting Policy
Stanley But	Manager, Economics and Load Forecasting

Henry Andre	Manager, Transmission and Distribution Pricing, Regulatory Affairs

In addition, Hydro One called the following additional witnesses:

Mitchell Rothman	Managing Consultant, Power Advisory LLC
John Dalton	President, Power Advisory LLC
Robert Yardley	Executive Advisor, PA Consulting

Hydro One also presented two Independent Electricity System Operator (IESO) witnesses:

Darren Finkbeiner	Manager, Market Development, IESO
Ira Shavel	Vice-President, Charles River Associates

Witnesses called by the intervenor the Association of Major Power Consumers in Ontario:

Adam White	President and CEO, AITIA Analytical Inc.
Anindya Sen	Associate Professor, Economics, University of Waterloo, Waterloo Ontario
Darren MacDonald	Director of Energy, Gerdau Ameristeel Corporation
Paul Dottori	Vice-President, Energy Environment and Technology, Tembec Inc.

APPENDIX B

HYDRO ONE NETWORKS INC.
2011 AND 2012 ELECTRICITY TRANSMISSION
REVENUE REQUIREMENT AND RATES

DECISION WITH REASONS

BOARD FILE NO. EB-2010-0002

DECISION ON HYDRO ONE MOTION

DECEMBER 23, 2010

EB-2010-0002

Transcript: Motion Hearing, July 20, 2010, page 29

DECISION ON MOTION:

MR. SOMMERVILLE: The Board has reached a decision on the motion, and will provide our decision on that now, to be followed by our decision with respect to the rest of the Issues List.

The Board denies the motion. It is the Board's view that severing the so-called H5 charge determinant proposal from this proceeding is both inappropriate and inefficient. It is the Board's finding that the parties necessary for appropriate consideration of the matter are, in fact, parties to this case, and they will have the usual opportunities to file, challenge, support, and test all of the evidence surrounding the proposal.

The Board will consider making provision for a technical conference in September to deal with this, to deal with this issue, should it seem to be advisable.

The Board, in considering the issue, will be mindful of the general desirability of having rates -- a rates decision in place to be effective January 1st, 2010, and the timing issues -- I beg your pardon, 2011 –- and the timing issues elucidated by IESO and Hydro One.

So it is the Board's view that we will consider this issue as originally drafted in the draft Issues List, 8.1, in this proceeding.

APPENDIX C

HYDRO ONE NETWORKS INC.
2011 AND 2012 ELECTRICITY TRANSMISSION
REVENUE REQUIREMENT AND RATES

DECISION WITH REASONS

BOARD FILE NO. EB-2010-0002

ISSUES LIST

DECEMBER 23, 2010

HYDRO ONE NETWORKS INC.
EB-2010-0002
APPROVED ISSUES LIST

1. GENERAL

1.1 Has Hydro One responded appropriately to all relevant Board directions from previous proceedings?

1.2 Are Hydro One's economic and business planning assumptions for 2011/2012 appropriate?

1.3 Is the overall increase in 2011 and 2012 revenue requirement reasonable?

2. LOAD FORECAST and REVENUE FORECAST

2.1 Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

2.2 Are Other Revenue (including export revenue) forecasts appropriate?

3. OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

3.1 Are the proposed spending levels for, Sustaining, Development and Operations OM&A in 2011 and 2012 appropriate, including consideration of factors such as system reliability and asset condition?

3.2 Are the proposed spending levels for Shared Services and Other O&M in 2011 and 2012 appropriate?

3.3 Are the 2011/12 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

3.4 Are the OM&A development costs allocated to the "IPSP and Other Preliminary Planning Costs" deferral account for 2009, 2010, 2011 and 2012 appropriate?

3.5 Are the methodologies used to allocate Shared Services and Other O&M costs to the transmission business and to determine the transmission overhead capitalization rate for 2011/12 appropriate?

3.6 Are the amounts proposed to be included in the 2011 and 2012 revenue requirements for income and other taxes appropriate?

3.7 Is Hydro One Networks' proposed depreciation expense for 2011 and 2012 appropriate?

4. CAPITAL EXPENDITURES and RATE BASE

4.1 Are the amounts proposed for rate base in 2011 and 2012 appropriate?

4.2 Are the proposed 2011 and 2012 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

4.3 Are the proposed 2011 and 2012 levels of Shared Services and Other Capital expenditures appropriate?

4.4 Are the methodologies used to allocate shared services and other capital expenditures to the transmission business, appropriate? 3.7 Is Hydro One Networks' proposed depreciation expense for 2011 and 2012 appropriate?

4.5 Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?

4.6 Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets and support the O&MA and Capital expenditures for 2011/12?

5. COST OF CAPITAL/CAPITAL STRUCTURE

5.1 Is the proposed capital structure appropriate?

5.2 Is the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rates appropriate?

5.3 Is the forecast of long term debt for 2010-2012 appropriate?

6. DEFERRAL/VARIANCE ACCOUNTS

6.1 Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

6.2 Is the proposed disposition of the "IPSP and Other Preliminary Planning Costs" deferral account for 2009 appropriate?

6.3 Are the proposed new Deferral and Variance Accounts appropriate?

7. COST ALLOCATION

7.1 Is the cost allocation proposed by Hydro One appropriate?

8. CHARGE DETERMINANTS

8.1 Is it appropriate to implement "AMPCO's High 5 Proposal" in place of the status quo charge determinants for Network service?

9. GREEN ENERGY PLAN

9.1 Are the OM&A and capital amounts in the Green Energy Plan appropriate and based on appropriate planning criteria?

9.2 Are Hydro One's accelerated cost recovery proposals for the Bruce-to-Milton line and for Green Energy projects appropriate?

APPENDIX D

HYDRO ONE NETWORKS INC.
2011 AND 2012 ELECTRICITY TRANSMISSION
REVENUE REQUIREMENT AND RATES

DECISION WITH REASONS

BOARD FILE NO. EB-2010-0002

DECISION ON CME MOTION

DECEMBER 23, 2010

EB-2010-0002
Transcript: Oral Hearing, Volume 1, September 21, 2010, page 41

DECISION:

MR. SOMMERVILLE: Thank you. Please be seated. The Board has arrived at a decision with respect to the motion.

The motion is granted. In the Board's view, there is probative value in this documentation of the evolution of the company's thought with respect to its business plan, which ultimately culminated in the application that we're dealing with in this case.

The Board notes that these are highly formalized documents, seeking the approval of the board, signed by the president and the chief financial officer of the corporation. The fact that the approval sought was not limited, nor were the documents limited, to the transmission side of the business is not fatal to their value insofar as they demonstrate and seek the approval of the board with respect to the business plan which culminated in the application.

The Board does consider that it has the discretion to deny admissibility to materials where the probative value is obviously outweighed by the prejudicial effect of the material. The Board does not consider this to be such a case.

In the Board's view, the prejudicial effect, specifically the creation of an inhibition of discussion around the Hydro One board table, is not convincing in this case. The highly detailed and formal nature of these documents, as I have noted, signed by the president and the chief financial officer, suggest that they are obviously not records of discourse, conversation, debate, nor could they consider it to be genuinely formative with respect to the points of view expressed in the documents.

So on that basis, the Board grants the motion.

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BY E-MAIL AND WEB POSTING

November 10, 2011

To: All Licensed Electricity Distributors and Transmitters
All Gas Distributors
Ontario Power Generation Inc.
All Registered Intervenors in 2012 Cost of Service Applications

Re: Cost of Capital Parameter Updates for 2012 Cost of Service Applications for Rates Effective January 1, 2012

The Ontario Energy Board (the "Board") has determined the values for the Return on Equity ("ROE") and the deemed Long-Term ("LT") and Short-Term ("ST") debt rates for use in the 2012 rate year cost of service applications for rates effective January 1, 2012. The ROE and the LT and ST debt rates are collectively referred to as the Cost of Capital parameters. The updated Cost of Capital parameters are calculated based on the formulaic methodologies documented in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (the "Report"), issued December 11, 2009. The Board considers the Cost of Capital parameter values shown in the table that follows, and the relationships between them, reasonable and representative of market conditions at this time.

Cost of Capital parameters for rates effective January 1, 2012

Based on the methodologies set out in the Report and September 2011 data from the Bank of Canada, *Consensus Forecasts* and Bloomberg LLP, the Board has determined that the updated Cost of Capital parameters for 2012 cost of service rate applications for rates effective January 1, 2012 are:

Cost of Capital Parameter	Value for 2012 Cost of Service Applications for January 1, 2012 rate changes
ROE	9.42%
Deemed LT Debt rate	5.01%
Deemed ST Debt rate	2.08%

Detailed calculations of the Cost of Capital parameters are attached.

Every year, the Board updates the Cost of Capital parameters for use in setting rates for natural gas and electricity utilities for the coming rate year. The Board has normally updated the parameters once each year for rates effective May 1. Beginning in 2011, in light of certain applications requesting and approved for January 1 effective dates for rate changes, the Board advanced its determination of the values for the Cost of Capital parameters based on the data available three months in advance of the January 1, 2011 date. On November 15, 2010, the Board issued a letter announcing updated Cost of Capital parameters for rates effective January 1, 2011. Also in that letter the Board stated that cost of service applications with rates effective May 1, 2011 would have updated Cost of Capital parameters based on data for January 2011. The Board is continuing this approach of calculating and publishing updated Cost of Capital parameters at least twice a year, for effective dates for rates of January 1 and May 1.

For rates with effective dates in 2012, beginning with January 1, 2012, the Board has updated the Deemed ST Debt rate parameters based on: (i) the September 2011 survey from Canadian banks for the spread over the Bankers' Acceptance rate of 3-month short-term loans for R1-low commercial customers for the short-term debt rate; and (ii) data for three months prior to the effective date of January 1, 2012 from the Bank of Canada, *Consensus Forecasts*, and Bloomberg LLP, per the methodologies documented in the Report.

Updated Cost of Capital parameters for rates effective May 1, 2012 will be published once data for January 2012 become available.

All queries on the Cost of Capital parameters should be directed to the Board's Market Operations hotline, at 416 440-7604 or market.operations@ontarioenergyboard.ca.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Attachment

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations

(assuming January 1, 2012 effective date for rate changes)

Return on Equity and Deemed Long-term Debt Rate

Step 1: Analysis of Business Day Information in the Month

Month: September 2011

		Bond Yields (%)			Bond Yield Spreads (%)	
		Government of Canada		A-rated Utility	30-yr Govt over 10-yr Govt	30-yr Util over 30-yr Govt
Day		10-yr	30-yr	30-yr		
1	1-Sep-11	2.39	3.04	4.62	0.65	1.58
2	2-Sep-11	2.30	2.96	4.55	0.66	1.59
3	3-Sep-11					
4	4-Sep-11					
5	5-Sep-11	2.30	2.96	4.55	0.66	1.59
6	6-Sep-11	2.24	2.92	4.51	0.68	1.59
7	7-Sep-11	2.27	2.95	4.54	0.68	1.59
8	8-Sep-11	2.21	2.89	4.50	0.68	1.61
9	9-Sep-11	2.11	2.81	4.41	0.70	1.60
10	10-Sep-11					
11	11-Sep-11					
12	12-Sep-11	2.14	2.81	4.39	0.67	1.58
13	13-Sep-11	2.20	2.84	4.43	0.64	1.59
14	14-Sep-11	2.20	2.85	4.44	0.65	1.58
15	15-Sep-11	2.30	2.92	4.55	0.62	1.63
16	16-Sep-11	2.29	2.93	4.54	0.64	1.61
17	17-Sep-11					
18	18-Sep-11					
19	19-Sep-11	2.19	2.87	4.46	0.68	1.59
20	20-Sep-11	2.20	2.86	4.44	0.67	1.58
21	21-Sep-11	2.12	2.77	4.37	0.64	1.61
22	22-Sep-11	2.02	2.68	4.32	0.66	1.64
23	23-Sep-11	2.08	2.71	4.28	0.63	1.58
24	24-Sep-11					
25	25-Sep-11					
26	26-Sep-11	2.15	2.77	4.37	0.62	1.60
27	27-Sep-11	2.20	2.83	4.43	0.63	1.61
28	28-Sep-11	2.20	2.83	4.47	0.63	1.65
29	29-Sep-11	2.22	2.84	4.51	0.62	1.67
30	30-Sep-11	2.16	2.77	4.41	0.62	1.64
31						
		2.20	2.85	4.46	**0.652**	**1.605**
	Sources:	*Bank of Canada*		*Bloomberg L.P.*	❶	❷

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: *Consensus Forecasts*	Publication Date:	September 12, 2011	
	3-month	12-month	Average
September 2011	2.600	2.900 ❸	**2.750** %

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	③	2.750 %
Actual Spread of 30-year over 10-year Government of Canada Bond Yield (from Step 1)	①	0.652 %
Long Canada Bond Forecast (LCBF)	❹	**3.402** %

Step 4: Return on Equity (ROE) forecast

Initial ROE			9.75 %
Change in Long Canada Bond Yield Forecast from September 2009			
LCBF (September 2011) (from Step 3)	④	3.402 %	
Base LCBF		4.250 %	
Difference		-0.848 %	
0.5 X Difference			-0.424 %
Change in A-rated Utility Bond Yield Spread from September 2009			
A-rated Utility Bond Yield Spread (September 2011) (from Step 1)	②	1.605 %	
Base A-rated Utility Bond Yield Spread		1.415 %	
Difference		0.190 %	
0.5 X Difference			0.095 %
Return on Equity based on September 2011 data			**9.42** %

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for September 2011 (from Step 3)	④	3.402 %
A-rated Utility Bond Yield Spread September 2011 (from Step 1)	②	1.605 %
Deemed Long-term Debt Rate based on September 2011 data		**5.01** %

References on Calculation Methods:

- **Return on Equity**: Appendix B of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009.
- **Deemed Long-term Debt Rate**: Appendix C of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009.

Ontario Energy Board
Commission de l'Énergie de l'Ontario

Attachment: Cost of Capital Parameter Calculations
(assuming January 1, 2012 effective date for rate changes)

Deemed Short-term Debt Rate

Step 1: Average Annual Spread over Bankers Acceptance

Once a year, in January, Board staff contacts prime Canadian banks to get estimates for the spread of short-term (typically 90-day) debt issuances over Bankers' Acceptance rates. Up to six estimates are provided.

A.	over 90-day Bankers Acceptance		Date of input
Bank 1	85.0	bps	Sept., 2011
Bank 2	87.5	bps	Sept., 2011
Bank 3	100.0	bps	Sept., 2011
Bank 4	85.0	bps	Sept., 2011
Bank 5	100.0	bps	Sept., 2011
Bank 6			

B. Discard high and low estimates
If less than 4 estimates, take average without discarding high and low.

Number of estimates	5	
High estimate	100.0	bps
Low estimate	85.0	bps

C. Average annual Spread	90.833	bps	❶

Step 3: Deemed Short-Term Debt Rate Calculation

Calculate Deemed Short-term debt rate as sum of average annual spread (Step 1) and average 3-month Bankers' Acceptance Rate (Step 2)

Average Annual Spread	0.908	%	①
Average Bankers' Acceptance Rate	1.173	%	②
Deemed Short Term Debt Rate	**2.08**	%	

Step 2: Average 3-month Bankers' Acceptance Rate

Calculation of Average 3-month Bankers' Acceptance Rate during month of September 2011

Month:		**September 2011**	
	Day	**Bankers' Acceptance Rate (%) 3-month**	
1	1-Sep-11	1.17	%
2	2-Sep-11	1.17	%
3	3-Sep-11		
4	4-Sep-11		
5	5-Sep-11		
6	6-Sep-11	1.17	%
7	7-Sep-11	1.17	%
8	8-Sep-11	1.17	%
9	9-Sep-11	1.17	%
10	10-Sep-11		
11	11-Sep-11		
12	12-Sep-11	1.17	%
13	13-Sep-11	1.17	%
14	14-Sep-11	1.17	%
15	15-Sep-11	1.17	%
16	16-Sep-11	1.17	%
17	17-Sep-11		
18	18-Sep-11		
19	19-Sep-11	1.17	%
20	20-Sep-11	1.18	%
21	21-Sep-11	1.19	%
22	22-Sep-11	1.18	%
23	23-Sep-11	1.18	%
24	24-Sep-11		
25	25-Sep-11		
26	26-Sep-11	1.18	%
27	27-Sep-11	1.17	%
28	28-Sep-11	1.17	%
29	29-Sep-11	1.17	%
30	30-Sep-11	1.17	%
31			
		1.173	%
		❷	

Sour Bank of Canada / Statistics Canada
Series V39071

Reference on Calculation Method:
• Appendix D of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* , issued December 11, 2009.

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BY E-MAIL AND WEB POSTING

November 15, 2012

To: All Licensed Electricity Distributors and Transmitters
All Gas Distributors
Ontario Power Generation Inc.
All Registered Intervenors in 2013 Cost of Service Applications

Re: Cost of Capital Parameter Updates for 2013 Cost of Service Applications for Rates Effective January 1, 2013

The Ontario Energy Board (the "Board") has determined the values for the Return on Equity ("ROE") and the deemed Long-Term ("LT") and Short-Term ("ST") debt rates for use in the 2013 cost of service applications for rates effective January 1, 2013. The ROE and the LT and ST debt rates are collectively referred to as the Cost of Capital parameters. The updated Cost of Capital parameters are calculated based on the formulaic methodologies documented in the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* (the "Report"), issued December 11, 2009.

Cost of Capital parameters for rates effective January 1, 2013

For rates with effective dates of January 1, 2013, the Board has updated the Cost of Capital parameters based on: (i) the September 2012 survey from Canadian banks for the spread over the Bankers' Acceptance rate of 3-month short-term loans for R1-low or A:- (A-stable) commercial customers for the short-term debt rate; and (ii) data for three months prior to the effective date of January 1, 2013 from the Bank of Canada, *Consensus Forecasts*, and Bloomberg LLP, per the methodologies documented in the Report.

The Board has determined that the updated Cost of Capital parameters for 2013 cost of service rate applications for rates effective January 1, 2013 are:

Cost of Capital Parameter	Value for 2013 Cost of Service Applications for January 1, 2013 rate changes
ROE	8.93%
Deemed LT Debt rate	4.03%
Deemed ST Debt rate	2.08%

Detailed calculations of the Cost of Capital parameters are attached.

The Board considers the Cost of Capital parameter values shown in the above table, and the relationships between them, to be reasonable and representative of market conditions at this time.

Updated Cost of Capital parameters for rates effective May 1, 2013 will be published once data for January 2013 become available.

All queries on the Cost of Capital parameters should be directed to the Board's Market Operations hotline, at 416-440-7604 or market.operations@ontarioenergyboard.ca.

Yours truly,

Original Signed By

Kirsten Walli
Board Secretary

Attachment

Cost of Capital Parameter Calculations
Return on Equity and Deemed Long-term Debt Rate

Step 1: Analysis of Business Day Information in the Month

Month: September 2012

		Bond Yields (%)			Bond Yield Spreads (%)	
		Government of Canada		A-rated Utility	30-yr Govt over 10-yr Govt	30-yr Util over 30-yr Govt
Day		10-yr	30-yr	30-yr		
1	1-Sep-12					
2	2-Sep-12					
3	3-Sep-12					
4	4-Sep-12	1.74	2.31	3.78	0.57	1.47
5	5-Sep-12	1.75	2.33	3.80	0.58	1.47
6	6-Sep-12	1.84	2.40	3.87	0.56	1.47
7	7-Sep-12	1.85	2.43	3.90	0.58	1.47
8	8-Sep-12					
9	9-Sep-12					
10	10-Sep-12	1.83	2.42	3.88	0.59	1.46
11	11-Sep-12	1.85	2.44	3.91	0.59	1.47
12	12-Sep-12	1.90	2.49	3.95	0.59	1.46
13	13-Sep-12	1.88	2.47	3.93	0.59	1.46
14	14-Sep-12	1.97	2.54	4.01	0.57	1.47
15	15-Sep-12					
16	16-Sep-12					
17	17-Sep-12	1.94	2.52	3.98	0.58	1.46
18	18-Sep-12	1.91	2.49	3.94	0.58	1.45
19	19-Sep-12	1.89	2.46	3.91	0.57	1.45
20	20-Sep-12	1.86	2.42	3.88	0.56	1.46
21	21-Sep-12	1.85	2.42	3.86	0.57	1.44
22	22-Sep-12					
23	23-Sep-12					
24	24-Sep-12	1.82	2.39	3.83	0.57	1.44
25	25-Sep-12	1.81	2.38	3.82	0.57	1.44
26	26-Sep-12	1.75	2.33	3.76	0.58	1.43
27	27-Sep-12	1.75	2.35	3.78	0.60	1.43
28	28-Sep-12	1.73	2.32	3.77	0.59	1.45
29	29-Sep-12					
30	30-Sep-12					
31						
		1.84	2.42	3.87	**0.578**	**1.455**
	Sources:	*Bank of Canada*		*Bloomberg L.P.*	❶	❷

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: *Consensus Forecasts* Publication Date: September 10, 2012

	3-month	12-month		Average	
September 2012	1.800	2.200	❸	**2.000**	%

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	③	2.000	%
Actual Spread of 30-year over 10-year Government of Canada Bond Yield (from Step 1)	①	0.578	%
Long Canada Bond Forecast (LCBF)	❹	**2.578**	%

Step 4: Return on Equity (ROE) forecast

Initial ROE				9.75 %
Change in Long Canada Bond Yield Forecast from September 2009				
LCBF (September 2012) (from Step 3)	④	2.578	%	
Base LCBF		4.250	%	
Difference		-1.672	%	
0.5 X Difference				-0.836 %
Change in A-rated Utility Bond Yield Spread from September 2009				
A-rated Utility Bond Yield Spread (September 2012) (from Step 1)	②	1.455	%	
Base A-rated Utility Bond Yield Spread		1.415	%	
Difference		0.040	%	
0.5 X Difference				0.020 %
Return on Equity based on September 2012 data				**8.93** %

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for September 2012 (from Step 3)	④	2.578	%
A-rated Utility Bond Yield Spread September 2012 (from Step 1)	②	1.455	%
Deemed Long-term Debt Rate based on September 2012 data		**4.03**	%

References on Calculation Methods:
- **Return on Equity**: Appendix B of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.
- **Deemed Long-term Debt Rate**: Appendix C of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.

Cost of Capital Parameter Calculations
Deemed Short-term Debt Rate

Step 1: Average Annual Spread over Bankers Acceptance

Once a year, in January, Board staff contacts prime Canadian banks to get estimates for the spread of short-term (typically 90-day) debt issuances over Bankers' Acceptance rates. Up to six estimates are provided.

A.	over 90-day Bankers Acceptance (basis points)		Date of input
Bank 1	105.0	bps	Sept., 2012
Bank 2	82.5	bps	Sept., 2012
Bank 3	100.0	bps	Sept., 2012
Bank 4	80.0	bps	Sept., 2012
Bank 5	80.0	bps	Sept., 2012
Bank 6			

B. Discard high and low estimates
If less than 4 estimates, take average without discarding high and low.

Number of estimates	5	
High estimate	105.0	bps
Low estimate	80.0	bps

C. Average annual Spread	87.500	bps	❶

Step 3: Deemed Short-Term Debt Rate Calculation

Calculate Deemed Short-term debt rate as sum of average annual spread (Step 1) and average 3-month Bankers' Acceptance Rate (Step 2)

Average Annual Spread	0.875	%	①
Average Bankers' Acceptance Rate	1.204	%	②
Deemed Short Term Debt Rate	**2.08**	%	

Step 2: Average 3-month Bankers' Acceptance Rate

Calculation of Average 3-month Bankers' Acceptance Rate during month of September 2012

Month: **September 2012**

	Day	**Bankers' Acceptance Rate (%) 3-month**	
1	1-Sep-12		
2	2-Sep-12		
3	3-Sep-12	Bank holiday	%
4	4-Sep-12	1.21	%
5	5-Sep-12	1.21	%
6	6-Sep-12	1.21	%
7	7-Sep-12	1.21	%
8	8-Sep-12		
9	9-Sep-12		
10	10-Sep-12	1.21	%
11	11-Sep-12	1.21	%
12	12-Sep-12	1.21	%
13	13-Sep-12	1.21	%
14	14-Sep-12	1.20	%
15	15-Sep-12		
16	16-Sep-12		
17	17-Sep-12	1.20	%
18	18-Sep-12	1.20	%
19	19-Sep-12	1.20	%
20	20-Sep-12	1.20	%
21	21-Sep-12	1.20	%
22	22-Sep-12		
23	23-Sep-12		
24	24-Sep-12	1.20	%
25	25-Sep-12	1.20	%
26	26-Sep-12	1.20	%
27	27-Sep-12	1.20	%
28	28-Sep-12	1.19	%
29	29-Sep-12		
30	30-Sep-12		
31			
		1.204	%
		❷	

Source: Bank of Canada / Statistics Canada
Series V39071

Reference on Calculation Method:
• Appendix D of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.

The Conference Board of Canada
Insights You Can Count On

Briefing March 2004

Electricity Restructuring
Opening Power Markets

About the Electricity Restructuring Series
This briefing is the fifth in a series that highlights key learnings from the experience of North American and U.K. electricity restructuring initiatives over the past decade. The briefings focus on the impacts of public policies in the areas of economic regulation, air quality and climate change on investment in electricity generation and transmission, and on trade across regions.

Investment is needed in transmission capacity. Electricity in Canada and the United States has become a North American phenomenon, with growing volumes of exports and imports between the two countries. The result is a highly interconnected, complex continental network—one that is flexible in responding to fluctuations in demand and supply, but is more vulnerable in the event of a major failure.

Yet challenges exist to getting investment. North America's evolving electricity sector must find ways to raise the level of investment in order to strengthen the transmission infrastructure. This briefing suggests possibilities, while outlining why investment is needed and identifying some of the obstacles.

INVESTMENT IS NEEDED

Under-investment in critical infrastructure cannot be sustained. Witness the Aug. 14 blackout. Its cascading nature underscored the need not only for a more resilient electricity infrastructure, but also for a less brittle system overall.

New demands due to trade, combined with an aging system, have created congestion on transmission lines. This congestion has given rise to an untenable situation with respect to reliability, and constitutes a barrier to electricity trade. In fact, the lack of adequate transmission has become a bottleneck to the development of generation in several areas. An inadequate infrastructure not only threatens electricity reliability; it also contributes to volatility in electricity prices and higher prices for consumers in constrained zones.

Transmission lines are strained and overtaxed, largely because investment in continental transmission capacity has stagnated while network congestion has increased. The North American Electric Reliability Council (NERC) reported in 2002 that the number of power deals that could not be fulfilled due to transmission constraints quintupled, from 300 in 1998 to 1,500 in 2002.[1] This has created local market power problems and has complicated the operation of wholesale power markets. The grid, in its grim condition, requires upgrading that is estimated to be in the order of $50 billion US.

And money isn't the only issue. Arguably, there are imperfections in transmission governance arrangements that further erode the effectiveness of the transmission infrastructure. The transmission system remains fragmented, with too many system operators relying on incompatible scheduling, transmission pricing and emergency management mechanisms.[2]

Making transmission improvements comprises only one element among many in moving towards the objective of meeting future power needs. Nevertheless, facilitating transmission investment is an important objective, since transmission is currently the factor that most limits the supply of electricity in North America.

Given the deficiencies of the current infrastructure, investment is clearly required to accommodate cross-border exchanges and to ensure the reliability and security of electricity.

Improving transmission is vital—but we must do more to meet North America's power needs, including removing obstacles to investment.

However, investors who are considering the transmission sector in North America face increased risks. Why? In a nutshell, the sector lacks sufficient commercial incentives and potential rewards to balance new risks. We need to remove barriers and address disincentives to transmission investment either through regulatory mechanisms or market signals, particularly as markets continue to integrate.

CHALLENGES FOR INVESTMENT

A number of regulatory issues and uncertainties are limiting investment in new transmission capacity.

PLANNING

A lack of integrated and co-ordinated planning for transmission between jurisdictions exists. The focus on regional supply has limited the expansion of the transmission system; in general, the main problem lies in insufficient regional integrated planning. Moreover, the cumbersome procedures for finding sites and obtaining permission for new facilities deter investors. Multiple authorities are responsible for planning and building new facilities, and investors must endure long lead times before obtaining regulatory approval.[3] For example, three years' lead time is the current estimate to attain the necessary approval for transmission line work in the Pacific Northwest Economic Region. The "not in my back yard" factor is a particular challenge for investors in planning for, and obtaining, suitable new corridors.

The electricity sector suffers from a lack of integrated and co-ordinated planning for transmission.

REGULATED RATES

Investors are discouraged by limitations on the regulated cost recovery for transmission upgrading. Transmission companies are simply not seeing favourable risk/return ratios on their investments, and know that they can realize better returns in the United States, where regulated rates of return are much higher. Rates of return to Canadian firms for transmission projects are around 9 to 10 per cent, well below the 13 to 14 per cent available to U.S. companies.[4] These lower rates discourage investment in Canadian utilities. Moreover, investors are additionally deterred by the fact that existing cost-of-service rates do not reflect the economic value of the transmission grid.[5]

FINANCING

Obtaining desired levels of financing is also problematic. Following the Enron bankruptcy and the ensuing loss of market credibility, it has become more difficult for energy companies to get credit for working capital and to finance their investments. And the upshot is that companies have been curtailing or exiting energy trading and marketing, and energy trading activity is down more than 70 per cent in the United States.[6] In turn, there is a lack of financing to pursue projects,[7] which has reduced the incentive to pursue new infrastructure projects or new transmission connection technologies.

REGULATORY UNCERTAINTY

Several regulatory factors combine to create an unfavourable investment climate in the electricity sector:

- Changes in market restructuring policies in both Canada and the United States are ongoing.
- In light of the continuing attempts to create an even playing field in the wholesale power supply market through non-discriminatory access, there is indecision as to how transmission systems should be operated.[8]
- With increased regionalization, it is unclear who will own and operate the grid in the future. Despite regionalization, the authority to improve the grid remains with individual states and provinces. And, as the blackout demonstrated, key industry decision-makers are unsure of their regulatory options during emergencies or market events.[9]

ENCOURAGING INVESTMENT

Encouraging investment increasingly preoccupies the industry as a whole. The Canadian Electricity Association (CEA) has estimated that about $150 billion in investment will be required in the electricity sector over the next 20 years, either to replace aging capacity and infrastructure or to add to what already exists. And the industry will be relying on private capital for much of this future investment.[10]

To secure the substantial sums that will be required by the electricity sector over the next 20 years, several investment challenges must be overcome.

Key players have been pushing politicians for regulatory reform to encourage investment in transmission. For example, the Edison Electric Institute has urged the U.S. Congress to update federal laws that restrict critically needed investment in the power transmission system. The CEA, along with the Canadian Gas Association, is urging multi-jurisdictional efforts to improve the investment climate in Canada.

Ideally, a multifaceted approach should be designed to overcome investment challenges. This section presents five key elements that such an approach should encompass.

RATES OF RETURN AND DEPRECIATION

As the CEA has pointed out, investors must see reasonable rates of return on their capital.[11] Specifically, the CEA contends that rates of return should recognize the value that the transmission grid plays in the economy. Rates should include clear signals on congestion and losses to transmission users, and should encourage technological innovation.

Increases in regulated rates of return on infrastructure projects would provide better incentives for building transmission. Rate improvements could assist in enhancing the security and reliability of the overall electricity system by attracting new investment to reduce congestion, increase import/export capability, add capacity and support competitive markets. A more secure and reliable system would engender greater competition for infrastructure contracts and could lead to lower costs for such work and lower consumer prices.

The CEA has issued a call for substantially higher capital cost allowance (CCA) rates to reflect the economic life of depreciating assets and to permit expansion. “Given steadily growing demand and long lead times to plan and bring new supply and infrastructure on-line, a decision on CCA rates is urgently needed to allow utilities to build out infrastructure equivalent to approximately 35 per cent of existing capacity over the next two decades.”[12]

It is important that Canada’s rates be competitive with those of the United States so that both countries can maintain a solid pace of transmission infrastructure improvement.

Furthermore, the risk profile of new transmission facilities is generally greater than that for existing facilities. These greater risks—and the lack of regulatory recognition of these risks—may make utilities reluctant to pursue investment. Regulators should therefore recognize these additional risks when setting rates.[13]

Maintaining competitive rates is a necessary, but not a sufficient, condition for investment, however. It is important to improve rates in Canada, but, given that U.S. transmission companies are not investing adequately either, there are clearly other issues that must be addressed in order to get the investment that is so evidently needed.

PLANNING

The blackout prompted serious thought about planning, and the merits of regionalization. The U.S. Federal Energy Regulatory Commission (FERC) has argued that the blackout demonstrated the need for regional co-ordination and planning, and for national standards. FERC's regional transmission organization (RTO) system aims to formalize the regional planning process and efficiently manage the growth of the transmission system.[14] Standard Market Design (SMD), an attempt at standardization and regionalization, may boost infrastructure investment. SMD is a federal plan to standardize all U.S. wholesale power markets. The FERC proposal calls for a single set of market rules that would eliminate the differences between regional electricity markets. FERC views these differences as barriers that limit the ability of energy users to get access to lower-cost power resources.[15] The current energy bill delays SMD until 2007.

The Aug. 14 blackout underscored the need for planning, although differences of opinion exist as to how best to proceed.

Some states and provinces have chosen a different interpretation of the blackout, regarding it as an indication that they should isolate themselves on the grid to avoid problems. However some experts, such as Connie Hughes, Chair of the Ad Hoc Committee on Critical Infrastructure for the U.S. National Association of Regulatory Utility Commissioners, argues that there is no reason for breaking down power and energy trade between countries.[16] Although critics of regionalization view it as an infringement on state and provincial rights, integrated planning will likely work more effectively under a regionalized RTO system.

LOCATIONAL MARGINAL PRICING

Locational marginal pricing (LMP) is a market-pricing approach used to manage the efficient use of the transmission system. LMP sets prices specific to location. It aims to manage congestion by pricing electricity higher in locations where congestion exists, thus providing a precise market-based method for pricing electricity that includes the cost of congestion. By doing so, LMP also indicates where investment in new transmission facilities is most needed. LMP has been recognized as a significant improvement on flawed congestion management and uniform pricing systems.[17]

Some electricity markets have adopted or are adopting LMP: Pennsylvania New Jersey Maryland (PJM ISO) implemented LMP in 1998; New York (NY ISO) in 1999; New England (ISO-NE) in 2003.[18] And it appears to be advantageous; transmission investments are now being proposed in congested zones in these three jurisdictions.[19] Furthermore, FERC is promoting LMP as a means of managing electric transmission congestion. It is the proposed pricing model for many of the RTOs.[20]

LMP could help dissolve "load pockets"[21] and allocate scarce transmission resources more efficiently. Specifically, LMP provides better information for investment decisions by:

- identifying congested areas;
- producing transparent prices that assist investment analysis;
- helping to account for the value of upgrades to the system; and
- assisting in comparing the value of "competing" investment options.

LMP also supports efficient regional planning.

Despite the potential advantages of LMP, it is a complex approach that is not without its own challenges. Using pricing to provide incentives for expansion creates an inherent conflict—it lessens the motivation for transmission companies to deal with congestion, as they may be able to collect more revenues when it exists. To address this concern, New York State auctions the rights to recover congestion revenues to entities that do not control the grid.[22]

Realistically, LMP must be regarded as a necessary feature of a successful system, but not as a solution in itself. Ideally, LMP should be a complementary part of a larger suite of mutually reinforcing tools, both market and regulatory, that, acting together, improve the reliability and efficiency of a power system.[23]

MERCHANT TRANSMISSION

Another option to improve transmission capacity is to permit "merchant" transmission lines. These are projects, usually involving direct current lines, financed by private sector interests to export power over long distances and across borders on a fee-for-service basis. AltaLink is advocating merchant transmission lines, as is its American parent, Trans-Elect, Inc. Merchant transmission lines have the potential to alleviate transmission congestion issues. Moreover, several merchant transmission projects and long-distance transmission line projects have been proposed as means of connecting more "environmentally friendly" forms of power, such as hydro and wind, to their markets.

However, as a new industry, merchant transmission is unproven.[24] Investment in it is therefore more likely to play a significant role in addressing transmission constraints over the longer, rather than the shorter, term.

RELIABILITY STANDARDS

Electricity reliability, which had long rested on the back burner of political priorities, was quickly marched to the forefront this summer. The blackout, was, of course, the catalyst. It exposed the fact that the current system for maintaining reliability—which is based on standards with which utilities voluntarily comply—is no longer effective. The introduction of competition in wholesale electric markets has eroded the incentive for voluntary action. Now, more than ever, the electricity market needs mandatory standards, along with financial consequences for non-compliance.

NERC is developing a single set of reliability standards to replace its existing operating policies and planning standards. The new standards will address planning and operations, and will include compliance measures for each standard.[25] Legislation on this issue is being considered as part of the national energy bill before the U.S. Congress. Among the bill's measures is a plan to make reliability standards mandatory.[26] The bill has been on hold, but the Senate will conduct a second vote in January 2004. FERC Chairman Pat Wood recently announced that while federal legislation setting electric reliability requirements is the best fix for grid problems, FERC can act to boost reliability if Congress fails to pass a bill.[27]

Canada is in favour of the creation of a self-regulating organization tasked with ensuring reliability. With members from both Canada and the United States, this entity would develop, implement and enforce consistent reliability standards for the interconnected North American electricity grid, while respecting the jurisdiction of sovereign regulatory bodies.[28] The former Natural Resources Minister, Herb Dhaliwal, stated that Ottawa would consider bringing in mandatory reliability standards for power grid operators that could discipline those that do not toe the line.[29]

CANADIAN CHOICES IN A NORTH AMERICAN MARKET

The transmission system across Canada is not as strained as in the United States. Therefore, the urgency to improve transmission capacity in Canada is not as strong. However, considerable concern exists over the lack of interprovincial trade. North–south transmission capacity exceeds east–west capacity since infrastructure has developed on the basis of historical market demand.

Exhibit 1
North American Electricity Trade Is Bright

The single most significant energy trading relationship in the world is between Canada and the United States. Cross-border trade in electricity has been growing dramatically largely due to legislation in the United States, which, over the past 25 years, has encouraged the trading of electricity between and within jurisdictions. Over the last few years, it has also been bolstered by the North American Free Trade Agreement. A more integrated North American electricity market has meant increased integration of regional markets through regional transmission organizations (RTOs) and contractual arrangements.

In 1996, the U.S. Federal Energy Regulatory Commission (FERC) mandated open access for non-discriminatory electricity transmission that led to state and provincial reforms, such as the creation of wholesale trading. FERC imposed some reciprocity conditions upon foreign applicants that required them to open their transmission power grid along the lines adopted for the U.S. wholesale market. Then, in 1999, FERC ordered the creation of Regional Transmission Organizations (RTOs) by December 2001 to better co-ordinate planning; this invited Canadian utilities that buy from or sell electricity to the United States to participate.

Canada dominates U.S. electricity imports—in fact, we actually dominate U.S. *energy* imports. And the United States is increasingly relying upon Canadian energy supplies; almost 100 per cent of American electricity imports come from Canada.[1] Notably, for example, imports of power from BC Hydro arguably prevented California from experiencing widespread blackouts during the 2001 power crisis.[2] However, transmission investment has not kept pace with electricity demand or with generation investment over the past 15 years.

North–south transmission capacity continues to exceed east–west, and there are no strong signs of growth in inter-regional trade in North America. Baseline projections from the Energy Modeling Forum in the United States validate this trend.

American-owned companies continue to be active in Canada, especially in the deregulated provinces of Alberta and Ontario. Canadian companies, such as TransEnergie, Fortis, TransAlta and NS Power, are increasingly active in the U.S. market.

Given its integrated nature, a continental electricity sector appears to be here to stay.

1 This is according to Canada's most recent trade statistics (2001). Lawrence Martin, "Elbowing aside Brian's legacy," *The Globe and Mail*, June 4, 2003, p. A17.

2 Michael Den Tandt, "Energy-hogging U.S. can't stay sore at us forever," *The Globe and Mail*, April 3, 2003, p. B2.

3 Prices and Emissions in a Restructured Electricity Market, Energy Modeling Forum, Stanford University, May 2001.

The north–south trading of electricity supplies (particularly exports to the United States from Quebec, Manitoba and British Columbia) has been more prevalent, economical and effective than east–west transmission. While cross-border electricity trade is growing, inter-regional trade is not necessarily increasing. Trade is hindered by the fact that Canadian provinces tend to function as silos, with little interprovincial co-operation and extensive interprovincial barriers.

Strengthening east–west electricity trade could bring many advantages to Canada.

In light of the desire in Canada for better flow of electricity among provinces, it is incumbent upon us to explore the viability of strengthened east–west electricity trade in Canada.[30] Additional transmission infrastructure is needed to allow sources of generation, some of which are distant from major demand centres, to be brought to market. While most provinces are interconnected with their immediate neighbours, possible further development of east–west lines, notably those between Ontario and Manitoba, and Ontario and Quebec, must be further examined. A major study about transmission expansion in Canada is underway.[31] There may be significant costs to expanding east–west transmission in Canada, but there might also be environmental benefits. For example, if an Ontario–Manitoba line could supply some capacity to replace coal-fired generation in Ontario (consistent with Canada's climate change and Ontario's energy policies), then it may make good sense as a policy objective.[32]

Strengthening interprovincial links may assist in securing the long-term provincial supply needs, such as in the case of the Ontario–Manitoba link. Additionally, developing an east–west grid could be considered to be an investment in the future and an exercise in nation building.

Canada's priorities must be addressed within the context of the North American electricity market. The U.S. regulatory framework exerts strong influence over Canadian decisions regarding cross-border commercial activity in electricity. Within each country, measures can be taken to bolster integration, but regulatory policy must be co-ordinated across North America.

In moving forward with competitive electricity markets, there are sound reasons to enhance Canada–U.S. and interprovincial transmission transfer capability. But, in making decisions on how to proceed, Canada needs to carefully evaluate the merits and drawbacks of the U.S.-driven initiatives. If, as FERC proposes, membership in RTOs becomes essential for power trading in North America, then there will be significantly stronger reasons for Canadian membership in them. Canada is already facing decisions about joining RTOs, and it should pay particular attention to analyzing the advantages and disadvantages of joining with states in regional relationships.

Canada should also be aware that any decision to adopt SMD would affect not only the functioning of RTO markets, but also the roles of the independent market operators and system operators. The standardization of markets and the introduction of independent transmission providers would change the nature of the market, along with the players themselves. SMD could provide market safeguards and facilitate continental trade. But Canadian companies must carefully balance the potential competitiveness benefits that they could derive from SMD against the loss of independence that it would bring.

Canadians should also bear in mind that policy and regulation designed for the American situation may have unintended impacts on us and on our bilateral relationship. For instance, both the augmented continental movement of electricity and decisions regarding transmission capacity could have implications for competitiveness.[33] Thus, there is a need for ongoing Canada–U.S. dialogue and for building stronger relations, with the objective of minimizing cross-border discrepancies. Ergo, now might be an opportune time for Canada to examine the extent of its involvement with NERC. Moreover, in setting harmonized market rules, regulators should aim to accommodate jurisdictional realities.

MOVING AHEAD WITH OPEN ELECTRICITY MARKETS

Adequate transmission capacity is vital to an efficient electricity market. To strengthen the North American transmission grid, players in the Canadian electricity sector—regulators, investors, politicians and policy-makers—must make a number of decisions on key issues. In particular:

- In supporting transmission investment, the Canadian electricity sector must consider how best to prepare for an increasingly regionalized electricity system in North America.
- Utilities, transmission companies and system operators should consider the extent of their involvement and their roles in integrated planning.
- Canadian regulators should decide whether improved rates of return on invested capital and CCA rates would result in desired investment activity.
- Regulators should resolve whether LMP could provide additional incentives for new transmission investment and, at the same time, also support regional planning.
- In light of the pending U.S. energy legislation regarding mandatory reliability standards, governments must decide on the possible benefits of forming a new self-regulating reliability organization for North America.

In moving ahead on these issues, we cannot forget to encourage new technologies. They will increase the capacity and efficiency of existing networks and reduce line losses,[34] and will be vital in making grid capacity improvements sustainable.

Exhibit 2
Current Initiatives

- A report for the Federal-Provincial-Territorial Electricity Transmission Working Group was recently completed. The "Regional Electricity Transmission Grid Study" discusses current transmission constraints and barriers to transmission and generation development.
- The Canadian Electricity Association (CEA) has recently published recommendations for an integrated North American electricity market, specifically aimed at enhancing cross-border electricity trade. Interestingly, these proposals are similar to those put forth by the U.S. Federal Energy Regulatory Commission (FERC). The CEA measures include:
  - increased participation in RTOs (regional integration);
  - increased focus on harmonizing market rules;
  - enhancement of cross-border and interprovincial transmission transfer capability; and
  - co-ordination of critical infrastructure protection.[1]
- Ontario has recently formed the Electricity Conservation and Supply Tax Force.
- The May 2002 U.S. National Transmission Grid Study (NTGS), published by the U.S. Department of Energy, highlights many of the legacy transmission issues in the country and proposes 50 specific recommendations.[1]
- The North American Energy Working Group (NAEWG) report—*North America—Regulation of International Electricity Trade* is an overview of federal regulations in Canada, the United States and Mexico with respect to the authorization of the construction and operation of international power lines, and the authorization of electricity exports and imports.

1 Canadian Electricity Association, *Canadian electricity and the economy—The Integrated North American Electricity Market: Enhancing Opportunities for Cross Border Trading and Environmental Performance* (Toronto: Canadian Electricity Association, 2003).

Finally, to effectively address the current challenges preventing required investment in transmission infrastructure, a strategic and forward-looking Canadian plan must form part of a focused North American approach.

1 ICF Consulting, *The Cascading Blackout: Why Wasn't the Power Outage Contained?* Issue Paper, Fairfax, VA.

2 Paul L. Joskow, "The Difficult Transition to Competitive Electricity Markets in the U.S." (AEI-Brookings Joint Center for Regulatory Studies, July 2003).

3 Nickle's Energy Analects, July 21, 2003. According to Scott Thon, President and Chief Executive Officer of AltaLink.

4 Ibid.

5 New Concepts for the Transmission Grid [on-line]. Department of the Environment Workshop, August 2001. [cited November 2003] Available from <www.ornl.gov/HTSC/pdf/roadmap080301/dale.pdf>.

6 According to Russell J. Tucker, Edison Electric Institute. Presentation [on-line]—March 18, 2003. [cited December 2003] Available from <www.eia.doe.gov/oiaf/aeo/conf/tucker/tucker.ppt>.

7 Nickle's Energy Analects, July 21, 2003.

8 Opinion-editorial, August 15, 2003: "The Power Grid Needs Mandatory Reliability Standards and Infrastructure Investment." [on-line] Steve Wright, Bonneville Power Administrator. [cited December 2003] Available from <www.bpa.gov/corporate/kc/home/docs/2003/testimony_of_%20steve_wright_june_0604_2003%20.pdf>.

9 U.S. General Accounting Office, *Electricity Restructuring: 2003 Blackout Identifies Crisis and Opportunity for the Electricity Sector*, [on-line] November 2003. [cited December 2003] Available from <www.gao.gov/new.items/d04204.pdf>.

10 Hans Konow, CEA President, Nickle's Energy Analects, Oct. 3, 2003.

11 Canadian Electricity Association, *Canadian electricity and the economy—The Integrated North American Electricity Market: Enhancing Opportunities for Cross Border Trading and Environmental Performance* (Toronto: Canadian Electricity Association, 2003).

12 Nickle's Energy Analects, Oct. 3, 2003. Hans Konow, CEA President. CEA wants CCA rates to rise from 8 per cent to 20 per cent on new generation assets and from 4 per cent to 12 per cent on transmission and distribution assets.

13 These risks include cost disallowances, cost overages, equipment problems and revenue risk. See Navigant Consulting, *Regional Electricity Transmission Grid Study* (Toronto: Navigant Consulting, 2003), p. 63.

14 Department of Energy National Transmission Grid Study [on line]. [cited January 2004] Available from <www.eh.doe.gov/index.html>.

15 Energy User News, Jan. 31, 2003. [cited December 2003] Available from <www.energyusernews.com/>.

16 "Grid reliability essential: Hughes," *Financial Post*, Sept. 3, 2003.

17 "Initial Observations on LMP in Other Jurisdictions." Presentation by Andrew Pietrewicz, Ontario Independent Electricity Market Operator, Nov. 11, 2003.

18 LMP has also operated in the New Zealand market since 1996, and in some South American countries. LMP is being considered in Australia and Ontario, and is planned in California (CAISO), Texas (ERCOT), Midwest (MISO) and Southeast (SeTRANS).

19 "Initial Observations on LMP in Other Jurisdictions." Presentation by Andrew Pietrewicz, Ontario Independent Electricity Market Operator, Nov. 11, 2003.

20 "LMP and Financial Transmission Rights." Presentation by John D. Chandley, LECG Economics Finance, Nov. 11, 2003.

21 Load pockets are geographical areas in which the demand for electricity can exceed the capacity of local generating facilities and/or in which there is an electricity import limitation as a result of transmission line constraints.

22 Auction revenues are allocated to transmission owners and applied to embedded costs of transmission system (to reduce the transmission service charge paid by loads). From Pietrewicz.

23 "Initial Observations on LMP in Other Jurisdictions." Presentation by Andrew Pietrewicz, Ontario Independent Electricity Market Operator, Nov. 11, 2003.

24 Constraints to the development of merchant transmission include market imperfections, immaturity of the merchant transmission industry, significant market risks, and the free rider problem. See Navigant Consulting, *Regional Electricity Transmission Grid Study* (Toronto: Navigant Consulting, 2003), p. 91.

25 NERC Web site. [cited December 2003] Available from <www.nerc.com/>.

26 Barrie McKenna, "Senators block proposed energy bill," *The Globe and Mail*, Nov. 22, 2003, p. B3.

27 *Restructuring Today* [newsletter@restructuringtoday.com], Dec. 3, 2003.

28 Notes for an Address by the Honourable Herb Dhaliwal, PC, MP, (Former) Minister of Natural Resources Canada to the Canadian Electricity Association Washington Forum, Washington, D.C., March 19, 2002. [cited December 2003] Available from <www.nrcan.gc.ca/media/speeches/2002/200232_e.htm>.

29 Simon Tuck, "U.S. firm faces blackout blame," *The Globe and Mail*, Nov. 19, 2003.

30 Alternative options for improving transmission capacity include improving north–south links or boosting generation capacity in centres that require it.

31 The Regional Electrical Transmission Grid Study in Canada.

32 Given the cost of natural gas, expanding gas-based generation stations may be more expensive than getting hydro (e.g., from Manitoba), even with high transmission charges.

33 In the cases of some U.S. regions undergoing restructuring, a key motivation has been a desire to obtain lower-cost power for consumers. One source has been hydro power from Canada.

34 Transmission line losses—power lost due to wire resistance—are a function of distance transported from generator to demand.

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116 FERC ¶ 61,057
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

(Docket No. RM06-4-000; Order No. 679)

Promoting Transmission Investment through Pricing Reform

(Issued July 20, 2006)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: In this Final Rule, pursuant to the requirements of the Transmission Infrastructure Investment provisions in section 1241 of the Energy Policy Act of 2005, which adds a new section 219 to the Federal Power Act, the Federal Energy Regulatory Commission (Commission) is amending its regulations to establish incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. This Final Rule is intended to encourage transmission infrastructure investment.

EFFECTIVE DATE: This Final Rule will become effective [insert date 60 days after publication in the **FEDERAL REGISTER**].

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SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Promoting Transmission Investment through Pricing Reform — Docket No. RM06-4-000

FINAL RULE

ORDER NO. 679

(Issued July 20, 2006)

Paragraph Numbers

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Nora Mead Brownell, and Suedeen G. Kelly.

Promoting Transmission Investment through Pricing Reform — Docket No. RM06-4-000

FINAL RULE

Order No. 679

(Issued July 20, 2006)

I. Introduction

1. Pursuant to the directives in section 1241 of the Energy Policy Act of 2005 (EPAct 2005)[1] which added a new section 219 to the Federal Power Act (FPA), in this Final Rule the Commission provides incentives for transmission infrastructure investment that will help ensure the reliability of the bulk power transmission system in the United States and reduce the cost of delivered power to customers by reducing transmission congestion. The Rule does not grant outright any incentives to any public utility, but rather identifies specific incentives that the Commission will allow when justified in the context of individual declaratory orders or section 205 filings by public utilities under the FPA. A number of these incentives reflect departures from what the Commission has permitted in

[1] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 315 and 1283 (2005)..

the past and a willingness to consider much greater flexibility with respect to the nature and timing of rate recovery for needed transmission infrastructure. While the Commission in recent years has permitted higher rates of return and deviations from past ratemaking practices in a few individual transmission infrastructure cases, [2] we here determine generically that these types of ratemaking options and others should be considered on a broader basis for those applicants that can demonstrate that their infrastructure proposals meet section 219 requirements.

2. In reaching our determinations in this Final Rule, we have considered comments that reflect widely divergent views with respect to whether and when utilities should receive incentives and what they must demonstrate in order to receive particular incentives. As noted, the Rule does not grant incentives to any public utility but instead permits an applicant to tailor its proposed incentives to the type of transmission investments being made and to demonstrate that its proposal meets the requirements of section 219. Further, under the Rule, the Commission will permit incentives only if the incentive package as a whole results in a just and reasonable rate. For example, an incentive rate of return sought by an applicant must be within a range of reasonable

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[2] See Western Area Power, 99 FERC ¶ 61,306, reh'g denied, 100 FERC ¶ 61,331 (2002) (Western), aff'd sub nom. Public Utilities Commission of the State of California v. FERC, 367 F.3d 925 (D.C. Cir. 2004); Michigan Electric Transmission Co., LLC, 105 FERC ¶ 61,214 (2003) (METC); American Transmission Company, L.L.C., 105 FERC ¶ 61,388 (2003) (American Transmission); ITC Holdings Corp., 102 FERC ¶ 61,182, reh'g denied, 104 FERC ¶ 61,033 (2003) (ITC Holdings).

returns and the rate proposal as a whole must be within the zone of reasonableness before it will be approved.

3. An important component of this Rule is the willingness to provide procedural flexibility, including the use of expedited declaratory orders on permitted ratemaking treatments, to help with financing and up-front regulatory certainty for project investments. We are particularly attuned to the need for flexibility to support long-distance interstate projects that significantly reduce the cost of delivered power by reducing transmission congestion on the interstate grid.

4. The Final Rule provides incentive-based rate treatments to any public utility transmitting electric energy in interstate commerce that meets the requirements of section 219 and this Final Rule. The Commission will not limit an applicant's ability to seek incentive-based rate treatments based on corporate structure or ownership. In addition, the Final Rule provides additional incentives, to the extent within our jurisdiction,[3] to any transmitting utility or electric utility transmitting electric energy in interstate commerce that joins a Transmission Organization.[4] Finally, as explained below, to the extent our

[3] With regard to non-public utilities, although the Commission's regulatory authority is bound by statute, such entities could be covered by a public utility's incentive rate proposal by a separate agreement between the public utility and a non-public utility. See Bonneville Power Administration, et. al. v. FERC, 422 F.3d 408 (9th Cir. 2005).

[4] Transmission Organization is defined in 18 CFR 35.35(a)(2) of this Final Rule as "a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities." Electric Utility is defined in

(continued)

jurisdiction allows, we encourage public power entities to take advantage of the incentive-based rate treatments outlined in the Final Rule.

5. Some commenters have argued that few or no incentives are needed to encourage new transmission investment. We reject these comments as fundamentally inconsistent with section 219. Section 219 reflects Congress' determination that the Commission's traditional ratemaking policies may not be sufficient to encourage new transmission infrastructure. Although section 219 does not permit approval of rates that are inconsistent with section 205 or 206, section 219 nonetheless constitutes a clear directive that "the Commission <u>shall</u> establish, by rule, incentive-based . . . rate treatments . . . for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion" (emphasis added). We therefore cannot simply rely on existing ratemaking policy to faithfully implement section 219. This Final Rule therefore identifies a non-exclusive list of ratemaking reforms and requires applicants to tailor their proposals to fit the facts of their particular case.

6. We do agree, however, with the position of certain wholesale customers and state commissions that the Commission should not provide incentives that only serve to

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section 3(22) of the FPA as "any person or State agency (including any municipality) which sells electric energy; such term includes the Tennessee Valley Authority, but does not include any Federal power marketing agency." 16 U.S.C. 796(22). Transmitting Utility is defined in section 3(23) of the FPA as "any electric utility, qualifying cogeneration facility, qualifying small power production facility, or Federal power marketing agency which owns or operates electric power transmission facilities which are used for the sale of electric energy at wholesale." 16 U.S.C. 796(23).

increase rates without providing any real incentives to construct new transmission infrastructure. Section 219(a) states that transmission incentives should be "benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion" (emphasis added). The purpose of our Rule is to benefit customers by providing real incentives to encourage new infrastructure, not simply increasing rates in a manner that has no correlation to encouraging new investment. The Final Rule, therefore, makes clear that not every incentive identified herein will be necessary or appropriate for every new transmission investment. To provide guidance in this regard to potential applicants, we discuss below why certain incentives may, as a general matter, be better tailored to certain types of investments than others.

II. Background

7. Section 219 of the FPA requires the Commission to establish, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. Section 219(b) requires that the rule:

1. promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the facilities;

2. provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies);

3. encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities; and

4. allow the recovery of all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215 of the FPA, and all prudently incurred costs related to transmission infrastructure development, pursuant to section 216 of the FPA (transmission national interest corridors).

8. Section 219(c) requires that the Rule provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization and to ensure that any recoverable costs associated with joining may be recovered through transmission rates charged by the utility or through the transmission rates charged by the Transmission Organization that provides transmission service to the utility. Finally, section 219(d) provides that all rates approved under the Rule are subject to the requirements of sections 205 and 206 of the FPA,[5] which require that all rates, charges, terms and conditions be just and reasonable and not unduly discriminatory or preferential.

[5] 16 U.S.C. 824(d) and 824(e) (2000).

9. Congress directed the Commission to issue a Final Rule establishing incentive-based rate treatments for transmission construction within one year of enactment of EPAct 2005, or by August 8, 2006. The Commission issued a Notice of Proposed Rulemaking (NOPR) on November 18, 2005 seeking comment on the Commission's proposal to comply with section 219.[6] In the NOPR, the Commission proposed to amend Part 35 of Chapter I, Title 18 of the Code of Federal Regulations by eliminating paragraph 35.34(e) under Subpart F and adding paragraph 35.35 under Subpart G. The Commission received several hundred pages of comments. A list of the commenters appears in Appendix B. As explained below, based on the comments filed, the Commission clarifies and adopts the proposed regulations in the NOPR.

III. Overview

A. The Need for New Transmission Facilities

1. Background

10. As indicated in the NOPR, investment in transmission facilities in real dollar terms declined significantly between 1975 and 1998. Although the amount of investment has increased somewhat in the past few years, data for the most recent year available, 2003, shows investment levels still below the 1975 level in real dollars.[7] This decline in

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[6] Promoting Transmission Investment Through Pricing Reform, 70 FR 71409 (Nov. 29, 2005), FERC Stats. & Regs., Proposed Regs. ¶ 32,593 (2005).

[7] EEI Survey of Transmission Investment: Historical and Planned Capital Expenditures (1999-2008) at 3 (2005).

transmission investment in real dollars has occurred while the electric load using the nation's grid more than doubled.[8] Further, the record shows that the growth rate in transmission mileage since 1999 is not sufficient to meet the expected 50 percent growth in consumer demand for electricity over the next two decades.[9]

2. Comments

11. Many commenters agree that there is a significant need for new investment in transmission facilities. EEI states that, although increases in transmission investment are predicted over the 2004 to 2008 period, the industry still has not reached the optimal level of investment.[10] International Transmission notes that growth in transmission capacity has lagged behind the growth in peak demand over the last three decades and this trend is projected to continue through at least 2012.[11] International Transmission cites to studies

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[8] Barriers to Transmission Investment, Presentation by Brendan Kirby (U.S. Department of Energy, Oak Ridge National Laboratory), April 22, 2005 Technical Conference, Transmission Independence and Investment, Docket No. AD05-5-000 (April 22, 2005 Technical Conference).

[9] Energy Policy Act of 2005: Hearings before the House Subcommittee on Energy and Commerce, 109th Congress, First Sess. (2005) (Prepared statement of Thomas R. Kuhn, President of EEI).

[10] 2004 State of the Markets Report, Federal Energy Regulatory Commission, Staff Report by the Office of Market Oversight and Investigations, June 2005, at p 27.

[11] See Eric Hirst, U.S. Transmission Capacity: Present Status and Future Prospects, a study prepared for EEI and the U.S. Department of Energy Office of Electric Transmission and Distribution, June 2004 (Hirst) and Keeping Energy Flowing: Ensuring a Strong Transmission System to Support Consumer Needs for Cost-Effectiveness, Security and Reliability, a report of the Consumer Energy Council of America, Transmission Infrastructure Forum, January 2005. See also Affidavit of Jon E. Jipping,

(continued)

estimating the cost of power interruptions and fluctuations to range from between $29 billion and $135 billion annually,[12] the cost of the August 2003 Northeast-Midwest blackout to be between $4 billion and $10 billion,[13] congestion costs of $4.8 billion in the ISO/RTO markets of California, New York, New England, the Midwest and PJM for 1999 to 2002,[14] and increases in PJM congestion costs, from $499 million in 2003 to $808 million in 2004.[15]

12. Many transmission users and state commissions also agree that there is a need for additional investment in transmission infrastructure.[16]

13. However, some commenters dispute the need for new transmission investment. They assert the Commission has overlooked that investment in transmission has increased in recent years.[17] They also contend that investment in transmission by utilities

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Exhibit A to the Reply Comments of International Transmission (the transmission system purchased in Michigan was 2.5 to 7 years behind schedule in maintenance on key transmission facilities).

[12] Kristina LaCommare and Joseph Eto, Understanding the Cost of Power Interruptions to U.S. Electricity Consumers, Lawrence Berkeley National Laboratory (September 2004) at xiv.

[13] See Final Report on the August 14, 2003 Blackout in the United States and Canada by the U.S. – Canada Power System Outage Task Force (April 2004) at 1.

[14] See Hirst at 8.

[15] See 2004 PJM State of the Market Report at 37 (March 8, 2005).

[16] E.g., TDU Systems, APPA, and Maryland Commission.

[17] E.g., NASUCA and Connecticut DPUC.

in RTOs and ISOs has been significant, citing to the approximately $2 billion of approved spending in PJM since 2000. E.ON US asserts that wide-spread system shortages have rarely occurred during the past 40 or more years, and that there does not appear to be any trend line that would suggest that it is becoming a serious problem now.

3. Commission Determination

14. The issue of whether there is a need for new transmission investment that is sufficient to justify transmission incentives was put to rest by section 219. Section 219 mandates that the Commission "establish, by rule, incentive-based (including performance-based) rate treatments" and, in doing so, "promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce" (emphasis added). If this were not enough, the legislative mandate of section 219 is supported by abundant evidence, as discussed above, including the fact that transmission investment in real dollars terms is lower today than it was in 1975 when the load was significantly smaller and that, even with the transmission additions of recent years, the industry still incurs significant congestion costs due to inadequate transmission.

B. The Need for Incentives

1. Background

15. In section 219(a) of the FPA, Congress directed the Commission to establish incentive-based rate treatments to foster investment in transmission facilities.

2. Comments

16. Several commenters argue that incentive-based rates are not necessary to encourage transmission construction or that incentives will not accomplish the intended goal.[18] Others assert that reliance on incentives may increase the price of electricity without any real benefit.[19]

17. Commenters urge the Commission to limit the scope of any incentive-based treatments or to adopt mechanisms to ensure that they have their intended effect. For example, the New Mexico AG and TAPS assert that the Commission may implement an incentive-based mechanism by penalizing utilities or RTOs that fail to make investments necessary to ensure the reliability of the transmission grid. The Delaware Commission contends that providing incentives without assessing penalties for failure to meet obligations violates the just and reasonable standard. NASUCA states that it is unfair to provide incentives that increase utility profits but do not hold applicants accountable for performance. The Missouri Commission proposes that the Commission implement a process that determines performance-based return on equity. Other commenters recommend that the Commission make approval of any incentives conditional on the

[18] E.g., APPA, TAPS, NECOE, E.ON U.S., NARUC, and New Jersey Board.

[19] E.g., Connecticut DPUC, NASUCA, NECPUC, Delaware Commission, Missouri Commission, and New Mexico AG.

applicant showing a need for the incentive or that the facility would not have been built absent the incentive.

18. In contrast, a number of commenters, including EEI and a large number of utility and Transco commenters, argue that incentives are needed to foster investment in transmission facilities. EEI asserts that incentives are needed to stimulate planning and investment in national interest electric transmission corridors. NU states that the many risk factors associated with transmission investments, such as considerable time delays, negative public opinion of transmission construction, state siting uncertainties and recovery of project costs, justify incentives.

3. Commission Determination

19. Here again, the fundamental issue raised by certain commenters – whether transmission incentives are necessary to encourage new infrastructure – was put to rest by the plain language of section 219(a), which requires the Commission issue a rule that adopts "incentive-based . . . rate treatments." Certain commenters urge the Commission to adopt "penalties" in this rulemaking for entities that do not build sufficient transmission. We decline to do so here.

20. Other commenters do not oppose incentives outright, but rather are concerned with the extent to which incentives may increase rates to consumers. Those concerns are premature. The Final Rule does not grant incentive-based rate treatments or authorize any entity to recover incentives in its rates. Rather, it informs potential applicants of incentives that the Commission is willing to allow when justified. Before adopting any

incentive-based rate treatments for a particular company, the Commission will need to determine that the applicant has justified its specific incentive request. In addition, although the Commission intends to provide flexible procedural mechanisms by which an applicant may obtain an early determination of which incentives it may receive (e.g., through an expedited declaratory order proceeding), before recovering any incentives in its rates, specific rates must be approved under section 205 of the FPA.

C. Summary of the Nature and Applicability of Incentives Adopted by the Final Rule

21. The incentives adopted by this Final Rule are properly understood only in the context of the traditional regulatory principles they seek to further. The longstanding rule is that utility rate regulation must adequately balance both consumer and investor interests. It is not enough to ensure that investors are properly compensated, and it is not enough to ensure that consumers are protected against excessive rates. Our policies must ensure both outcomes and, in doing so, strike the appropriate balance between these twin objectives. In striking that balance, the courts have recognized that there is no single formula for establishing a just and reasonable rate. Rather, the test is whether the "end result" is just and reasonable.[20]

22. The traditional policies that we re-examine here reflect both fundamental precepts: the need to balance investor and consumer interests and the recognition that there is no

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[20] See FPC v. Hope Natural Gas Co., 320 U.S. 591, 602-03 (1944).

single formula for doing so. For example, in ensuring that rates produce adequate returns for investors, we do not set a single return on equity for all public utilities, nor do we presume that there is only one return on equity that is appropriate for any individual utility. Rather, our precedents require the establishment of a range of returns and we select an ROE within that range that reflects the facts and circumstances of a particular case. Similarly, our policies regarding the recovery of Construction Work in Progress (CWIP) seek to balance investor and consumer interests by allowing, in the typical case, 50 percent of CWIP in rate base. This policy balances investor and consumer interests in the ordinary case by permitting investors recovery of some construction costs on a current basis while also protecting consumers against full rate recovery before a particular facility is placed into service.

23. Our procedural regulations respecting rate recovery also seek to balance investor and consumer interests. For example, we allow public utilities to determine, as a general matter, the timing and frequency of when to seek a rate increase, which ensures that investors can file a rate increase when current rates are no longer adequate (e.g., when the utility is undergoing a large construction program). However, we also typically require a utility seeking a rate increase to expose all of its costs to review and therefore do not generally permit "single issue" rate filings (selective rate adjustment).

24. Section 219 requires the Commission to re-examine these and other policies to determine whether they continue to strike the appropriate balance in encouraging new transmission investment given the significant need for new transmission infrastructure in

the Nation. We do so in recognition of the unique and substantial challenges faced by large new transmission projects. Siting major new transmission lines is extraordinarily difficult, given the environmental and land use concerns associated with obtaining and permitting new rights-of-way. The experience of American Electric Power Corp. in taking 16 years to complete construction of a new high-voltage transmission line from Wyoming County, West Virginia to Jackson Ferry, Virginia represents an extreme example, but it is illustrative of the significant risks and challenges associated with siting large new transmission projects.[21]

25. These challenges and risks are underscored by the fact that, in many instances, new transmission projects will not be financed and constructed in the traditional manner. New transmission is needed to connect new generation sources and to reduce congestion. However, because there is a competitive market for new generation facilities, these new generation resources may be constructed anywhere in a region that is economic with respect to fuel sources or other siting considerations (e.g., proximity to wind currents), not simply on a "local" basis within each utility's service territory. To integrate this new generation into the regional power grid, new regional high voltage transmission facilities will often be necessary and, importantly, no single utility will be "obligated" to build such facilities. Indeed, many of these projects may be too large for a single load serving

[21] Although new section 216 of the FPA improves the siting process for certain new projects, it does not eliminate all risks faced by such projects nor does it address the risks faced by other projects that do not reside in a national interest transmission corridor.

entity to finance. Thus, for the Nation to be able to integrate the next generation of resources, we must encourage investors to take the risks associated with constructing large new transmission projects that can integrate new generation and otherwise reduce congestion and increase reliability. Our policies also must encourage all other needed transmission investments, whether they are regional or local, designed to improve reliability or to lower the delivered cost of power.

26. To address the substantial challenges and risks in constructing new transmission, the Final Rule identifies instances where our regulatory policies may no longer strike the appropriate balance in encouraging new investment. The Final Rule identifies several policies that should be adjusted, where appropriate on the facts of a particular case, to encourage new transmission investment or otherwise remove impediments to such investment. Although each reform adopted by the Final Rule constitutes an "incentive" as that term is used by section 219, this label has caused some confusion in the comments. It is true that our reforms adopted in the Final Rule provide "incentives" to construct new transmission, but they do not constitute an "incentive" in the sense of a "bonus" for good behavior. Rather, as we explain below, each will be applied in a manner that is rationally tailored to the risks and challenges faced in constructing new transmission. Not every incentive will be available for every new investment. Rather, each applicant must demonstrate that there is a nexus between the incentive sought and the investment being made. Our reforms therefore continue to meet the just and reasonable standard by achieving the proper balance between consumer and investor

interests on the facts of a particular case and considering the fact that our traditional policies have not adequately encouraged the construction of new transmission.

27. A few examples will illustrate this point. The Final Rule permits higher returns on equity for certain transmission investments. This may be appropriate in several contexts, such as where the risks of a particular project exceed the normal risks undertaken by a utility (and hence are not reflected in a traditional discounted cash flow (DCF) analysis) and where necessary to encourage creation of a Transco or participation in a Transmission Organization. However, this does not mean that every new transmission investment should receive a higher return than otherwise would be the case. For example, routine investments to meet existing reliability standards may not always, for the reasons discussed below, qualify for an incentive-based ROE.

28. The Final Rule also adopts incentives that are designed to reduce the risks of new investments. For example, the Final Rule provides that the Commission will provide assurance of recovery of abandoned plant costs if the project is abandoned for reasons outside the control of the public utility. Although this qualifies as an "incentive" under section 219, it is perhaps more properly characterized as reducing a regulatory barrier – the potential lack of recovery of costs – to infrastructure development. Moreover, this reform adequately balances consumer and investor interests because it is available only when a project is abandoned for reasons beyond the control of the public utility.

29. Our Final Rule also adopts certain reforms that affect the timing of recovery of new transmission investments. Given the long lead time required to construct new

transmission, and the associated cash flow difficulties faced by many entities wishing to invest in new transmission, the Final Rule provides that, where appropriate, the Commission will allow for the recovery of 100 percent of CWIP in rate base. Here again, we seek to remove an impediment – inadequate cash flow – that our current regulations can present to those investing in new transmission. We also will permit, where appropriate, the recovery of the costs of new transmission through a single issue rate filing without requiring the public utility to re-open all its transmission rates to review. We do not, however, suggest that such selective rate adjustments will be appropriate in all cases, as discussed in more detail below. Rather, as with each incentive adopted by the Final Rule, an applicant must show that there is a nexus between its proposal to make a single issue rate adjustment and the facts of its particular case.

D. Effective Date and Duration of Effectiveness For Incentives

1. Background

30. Congress directed the Commission to issue a rule establishing incentive-based rate treatments no later than one year after enactment of EPAct 2005, or by August 8, 2006.

2. Comments

31. Certain commenters urge the Commission to apply the rule to investments made before August 8, 2005 while others ask the Commission to apply the rule to investments made after August 8, 2005.[22] Certain commenters argue that the Commission should not

[22] E.g., Progress, NEMA, and PG&E.

approve incentives for facilities that are pending at the time the Final Rule becomes effective, while others request that the Commission not allow incentives for investment in facilities that an applicant already has committed to build or for Transcos that already exist.[23]

32. Several commenters argue that, once the incentives have been granted, the Commission should not eliminate them, or should do so only under very limited circumstances.[24] In contrast, others argue that the Commission should grant incentives for a specific time period or retain the flexibility to change or review any incentives if it is found the incentives provide no customer benefit.[25] The California Oversight Board requests that any authorized incentives be subject to refund.

33. KKR explains that, under certain circumstances, investors in transmission assets may need favorable rate treatment for a sufficient period of time to ensure an appropriate return on their capital, i.e., for a 15 to 30-year period.[26] KKR recommends that public utilities requesting incentive treatment for an extended period into the future propose criteria that can be used to evaluate that entity's performance during periodic evaluations. KKR notes that applicants may not always be able to meet certain proposed metrics due

[23] E.g., PG&E, Connecticut DPUC, NASUCA, TDU Systems and TANC.

[24] E.g., Progress, NEMA, EEI, Trans-Elect, and National Grid.

[25] E.g., TANC, Snohomish, Municipal Commenters, and TDU Systems.

[26] See also National Grid and EEI.

to circumstances beyond their control. For example, a transmission owner should not lose its incentive rate treatments if it does not succeed in meeting desired reductions in congestion because the applicant may not have complete control of the factors affecting congestion, such as generation additions, changes in load location and operation of neighboring systems, and RTO policies. KKR emphasizes that the Commission should retain the flexibility to assess an applicant's proposal as the facts and circumstances will vary case-by-case. Finally, KKR recommends that applicants be required to file a report on their performance every several years and that the Commission may initiate a proceeding to review incentives only if the criteria are not met. KKR explains that frequent reviews run the risk of distorting results due to the "lumpiness" of capital investment and the long time periods to make capital additions and for capital additions to have effects. Further, KKR states that frequent reviews will make long-term investments more uncertain and, hence, less likely. In supplemental comments, KKR asserts that higher ROEs are of material value for Transcos only when long-term. KKR cites International Transmission as an example, noting that it is only able to invest in excess of every dollar it earns back into its system due to the certainty afforded it by its rate compact, which is long-term, formula-based, and includes a reasonable ROE. The certainty and long-term horizon of International Transmission's rates give debt and equity investors in International Transmission comfort that they will ultimately receive an adequate return on their capital.

3. Commission Determination

34. Section 219 of the FPA became effective on August 8, 2005. Codification of section 219 on that date and the requirement for a rule authorizing investment incentives provided notice to the industry that Congress intended that the Commission provide incentive-based rate treatments promptly. Thus, the Final Rule will become effective 60 days after publication in the Federal Register. However, we clarify that any investment made in, or costs incurred for, transmission infrastructure after August 8, 2005 that ensures reliability or lowers the cost of delivered power by reducing transmission congestion will be eligible for incentive-based rate treatments under this Rule. Applicants seeking incentive-based rate treatments for investments made or costs incurred after August 8, 2005 will need to satisfy the requirements of this Rule to obtain and recover any incentives and will need to make an appropriate filing under section 205.

35. The fact that a proposed expansion was in a utility's expansion plan as of August 8, 2005 does not disqualify the project for incentive treatment. Inclusion of a facility in a plan does not mean that a project can or will get built. Even where a project already has been planned or announced, the granting of incentives may help in securing financing for the project or may bring the project to completion sooner than originally anticipated. Congress's directive that the Commission issue a rule within one year of enactment of EPAct 2005 shows that Congress intended for the Commission to take steps to bring new transmission on line expeditiously.

36. With respect to the issue of how long an incentive-based proposal should remain in effect, the Commission recognizes that it may be necessary to authorize incentives that may extend over several years in order to support investment in long-term transmission. It can be important to investors making long-term investments in long-lived facilities to be assured that a ratemaking proposal adopted prior to construction of those facilities will not later be altered in a manner that undermines the basis for the financing of those facilities. The Commission will therefore allow applicants to propose specific time periods by which their incentive-based proposals will not be "re-opened" in a manner incompatible with the nature of the initial approvals. However, to ensure that ratepayers are also adequately protected, we will require any applicants seeking such a fixed term for its plan to explain how ratepayers can be assured that such a plan is delivering the benefits that formed the basis for the Commission's initial approval of it. For example, an applicant may propose periodic progress assessments with appropriate metrics to measure how well the project is progressing and whether the proposed investment in new transmission is improving reliability or reducing congestion. Such metrics would provide the Commission a means to determine whether and how the applicant is providing the anticipated benefits and thus that the approved incentives need not be revisited. Because the scope and size of each project will differ, any applicant seeking incentive-based rate treatments may propose metrics for its project as well as the frequency for review of

those metrics.[27] An applicant may include its proposed metrics and any timetable for review in its section 205 rate filing seeking recovery of incentives.[28] Where such metrics are found to be needed and are approved by the Commission, an applicant would be required to submit information filings to the Commission consistent with the approved metrics and timetable. We clarify, however, that the metrics reviews will not be opportunities to re-argue the issues addressed in proceedings granting the incentive-based rates; they are for the purpose of measuring whether the plan is being implemented as initially approved.

IV. Discussion

A. Standard for Approval of Incentive-Based Rate Treatments

1. The Final Rule Applies to the Recovery of Costs Incurred to Ensure Reliability or to Reduce Transmission Congestion, or Both.

a. Background

37. Proposed § 35.35(d)(1) specifies that the Commission will authorize incentive-based rate treatments for investment by public utilities, including Transcos, in new transmission capacity that reduces the cost of delivered power by reducing congestion or promotes reliability, as demonstrated in an application to the Commission.

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[27] The information may include, as well as supplement, information provided in FERC-730, discussed in section V below.

[28] An applicant has the option to include metrics proposals in a declaratory order proceeding, but would also need to include them in the subsequent section 205 rate filing.

b. Comments

38. Many commenters urge the Commission to be flexible in applying the incentives.[29] Southern and the Nevada Companies assert the Commission should not require that facilities both improve regional reliability and reduce congestion to be eligible for an incentive ROE. They argue that the guiding factor should be to provide incentives that improve regional reliability and/or reduce transmission congestion. AEP urges the Commission to adopt a functional approach to determine whether a project qualifies for incentives. For example, AEP suggests that projects that connect newer technology generation or renewables be eligible for incentives. Upper Great Plains contends that incentives should be available for projects that support the development of new electric generation in recognition of the expected growth in electric consumption and the need for additional investment to keep pace.

39. Several commenters urge the Commission to establish criteria for transmission projects to demonstrate that they achieve Congress' goals before projects receive an incentive.[30] The New York Commission asks the Commission to convene a technical conference to develop the criteria.

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[29] E.g., FirstEnergy, Southern, Nevada Companies, AEP.

[30] E.g., AEP and New York Commission.

40. The Maryland Commission supports incentives that are forward-looking and targeted to support electric reliability, competitive markets and diversity in fuel sources, including renewable resources, in the short and long term.

c. Commission Determination

41. The purpose of section 219 of the FPA is to benefit consumers by promoting transmission capital investments that result in reliable and economically efficient transmission and generation. Congress did not enact section 219 in isolation. Section 219 is a part of a larger statutory framework in which Congress directed the Commission to take steps to address reliability of the bulk power system as well as to remedy the adverse effects of transmission congestion. For example, in new section 215 of the FPA Congress enacted a regulatory regime under which the Commission will, for the first time in its history, approve and enforce mandatory reliability standards for the nation's power grid.[31] In new section 216, Congress directed the Secretary of Energy to identify areas of the nation in which transmission congestion adversely affects consumers (national interest electric transmission corridors) and gave the Commission certain permitting authority to ensure timely construction of transmission facilities to remedy transmission congestion in those corridors. In section 1223 of EPAct 2005, Congress directed the Commission to encourage the deployment of advanced transmission technologies that

[31] See Order No. 672, Rules Concerning Certification of the Electric Reliability Organization; and Procedures or the Establishment, Approval, and Enforcement of Electric Reliability Standards, 71 FR 8662 (Feb. 17, 2006), FERC Stats. & Regs. ¶ 31,204 (2006).

increase the capacity, efficiency and reliability of an existing or new transmission facility. In enacting these provisions of EPAct, Congress made clear that it was equally concerned with reliability as well as the adverse impacts of transmission congestion and that the Commission should take steps to address both issues. New FPA section 219, which is complementary to these other EPAct provisions, directs the Commission to provide rate incentives for the purpose of ensuring reliability and reducing transmission congestion. However, nowhere in section 219 does the language say that the Commission may provide incentives only to applicants that propose to both improve reliability and reduce congestion. In fact, we believe it would be contrary to the intent of the new provisions, taken together, to limit incentives this way.

42. Consistent with the overall goals of Congress in EPAct 2005, and in particular its focus on reliability improvements and relief of transmission congestion, we interpret section 219 to promote capital investment in a wide range of infrastructure investments that can have either reliability or congestion benefits rather than investments that have both reliability and congestion benefits. The alternative to this reading would be to apply section 219 in a manner that would deny incentive-based rate treatments to a transmission facility that significantly enhances reliability but does not reduce the cost of delivered power by reducing transmission congestion. This would be contrary to a fundamental goal of EPAct 2005 to improve reliability of the interstate transmission grid. We do not consider such an interpretation to be reasonable. In any event, we expect there will be few transmission projects that provide one type of benefit but not the other.

43. Commenters seeking a narrow reading of section 219 are primarily concerned with the impact of any incentive-based rate treatment on an applicant's rates. These concerns are premature. Before the Commission will permit any applicant to recover incentives in its rates, the Commission will evaluate the rate impact under section 205 or 206 of the FPA. Interested parties may raise any rate concerns at that time. Further, our case-by-case approach ensures that the incentives granted will be tailored to particular circumstances. Finally, except for the rebuttable presumptions addressed below, we will not at this time establish more detailed criteria an applicant must meet to be eligible for incentive-based rate treatments. Establishing criteria now would limit the flexibility of the Rule or improperly pre-judge which projects are acceptable for incentives. The Commission will, on a case-by-case basis, require each applicant to justify the incentives it requests. Because these proceedings will provide ample opportunity for parties to comment on any incentive proposal, we do not see the need for a technical conference or detailed criteria now. This notwithstanding, we provide certain guidance, as described below, regarding the types of projects that may be particularly well suited to certain incentives and others that may not.

2. Other Criteria For Approval of Incentives

a. Comments

44. Numerous commenters seek additional conditions to be considered in the grant of incentives. Some argue that the number of incentives should be limited while others

recommend additional criteria that an applicant must satisfy[32] or that the incentives be limited to certain types of facilities. For example, TDU Systems assert that the Final Rule should specifically identify other incentives that will be considered under § 35.35(d)(viii) and specify the parameters for eligibility for the incentives. EEI, however, contends the Commission should allow individual companies to propose any incentives on a case-by-case basis because the individual companies are in a better position to understand the efficacy of particular incentive mechanisms. Similarly, National Grid requests clarification that the incentives are not mutually exclusive and transmission owners should be free to propose customized rate packages that include one or more of the incentives in combination.

45. With regard to additional conditions, some commenters argue, for example, that the Commission should authorize incentives only for proposals that recognize regional differences, that are the product of an open and inclusive regional transmission planning process, increase network capacity, or that respond to specific reliability or congestion concerns. TANC argues that the Commission should limit qualification for the incentives to those transmission projects that are 200 kV and above. NECOE argues that incentives should be provided to utilities that conform to good utility practice and minimize total costs. Also, NECOE asserts that, when more than one incentive is requested, the Commission should require the applicant to demonstrate why a single, appropriately

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[32] E.g., East Texas, TANC, and TAPS.

targeted incentive is insufficient. Several commenters urge the Commission to grant incentives for existing facilities and for maintenance of existing facilities.[33] The Southern Companies state that the Commission should grant incentives to proposals that resolve a significant inter or intra-regional constraint, or preclude or mitigate anticipated constraints that may or may not arise. Progress asserts that incentives should be granted to encourage installation of new software to better manage flowgates and calculate Available Transfer Capability values on existing transmission facilities. The Steel Manufacturers state that a utility does not deserve special rate treatment to maintain or upgrade its facility to comply with mandated reliability standards.

46. Several commenters urge the Commission to condition any incentive-based rate treatment on the applicant, among other things, divesting the subject facility to a Transco, demonstrating that the subject facility solves congestion constraints on a regional basis or results in significant new transfer capacity, complying with the 1992 and 1994 Policy Statements, showing that the facilities would not have been built absent the incentives, or showing that the facilities were not already necessary to meet NERC reliability criteria or normal load growth.[34] PJM proposes a tiered procedure to determine whether incentives are warranted. TDU Systems recommend that incentives should be denied to public

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[33] E.g., FirstEnergy, PSEG, AEP, EEI, Duquesne and MidAmerican.

[34] E.g., TDU Systems, APPA, TAPS, NRECA, NARUC, NASUCA, Connecticut DPUC, New Jersey Board, WPS.

utilities that have refused to provide requested relief from transmission congestion in the form of transmission upgrades or otherwise, until such congestion is remedied without the incentive rates.

47. Several commenters request that the Commission allow states to play a role in the approval or recovery of incentives because states may hinder recovery of incentives in bundled rates.[35] National Grid asserts that the Commission and states should have an alignment of interests on transmission investment and, therefore, there is no basis to believe that the rule will warrant shifts in states' roles.

b. Commission Determination

48. Congress has determined that there is a need for incentives, and has directed the Commission to issue a rule to provide them. Most of the prerequisites and preconditions raised in the comments reflect a desire to limit or circumscribe the nature or applicability of incentives that may be granted under the rule. We have considered these comments and do not believe that any of them should be adopted at this time. Some of them are consistent with our overall policy goals (such as the emphasis on regional planning) and, to that extent, we explain how we will factor those considerations into an analysis of a proposed incentive. However, some are inconsistent with the policy goals of section 219 because they will only serve to discourage transmission investment. Therefore, unless

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[35] E.g., CREPC, KCPL, Steel Manufacturers, Montana-Dakota, MidAmerican, and EEI.

adopted in other sections of this rule, we will not require applicants to satisfy the requirements proposed in the comments. For example, we reject arguments that an applicant must show that, but for the incentives, the expansion would not occur. Those arguments are based on commenters' conclusions that the Commission's prior issuances (i.e., Removing Obstacles order, the 1992 Policy Statement, or the innovative rate proposal in Order No. 2000) required an applicant to show need prior to receiving incentives. However, the Final Rule is based on a clear directive from Congress that does not require an applicant to show that it would not build the facilities but for the incentives. This notwithstanding, we do require applicants to show some nexus between the incentives being requested and the investment being made, i.e., to demonstrate that the incentives are rationally related to the investments being proposed.

49. We also consider our procedures for the approval of incentives to be comprehensive and, therefore, will not attempt to establish gradations regarding either approval requirements or the amount of incentive approved, as recommended by TANC, PJM, Industrial Consumers and others. Section 219 does not mandate higher returns for projects that are part of independent regional planning processes, nor does it require higher standards of review for projects that do not result from independent planning processes. As long as the project ensures reliability or reduces the cost of delivered power by reducing congestion, regardless of where it is located on the nationwide transmission grid, the project is eligible for incentive ratemaking.

50. We will not impose size limits on eligible transmission projects. Projects below 200 kV can have a significant impact on reliability or reduce congestion, and therefore would qualify for incentive treatment. We will also not condition approval of incentives on market power findings. Our regulations and penalties on market power and market behavior are sufficient inducements to ensure markets are not manipulated and, therefore, additional provisions are not necessary.

51. We will not deny incentives to public utilities that have not built transmission upgrades requested by transmission customers. The scope of this Rule is restricted to implementing the requirements of section 219; the appropriate means to address this issue is to file a complaint in a separate proceeding.

52. While the promotion of renewable energy projects supports other policy and regulatory objectives, we will not adopt separate rate-based incentives for renewable energy projects. Congress directed the Commission to issue a rule to ensure reliability or to reduce the cost of delivered power by reducing transmission congestion regardless of the nature of the energy carried over the new transmission facilities. We believe that, by providing incentives applicable to all transmission facilities, the Final Rule provides incentives for transmission to serve renewable resources and, therefore, additional incentives are not necessary.

53. Because section 219 provides a new directive to the Commission to permit greater incentives and does not on its face require an individual showing of need by incentive

applicants, we will not require compliance with the 1992 or 1994 Transmission Policy Statements as a precondition for approval of incentives.

54. With regard to state review, the Commission recognizes that incentives for many utilities are incorporated into rates that must receive state commission approval and that many decisions on siting and permitting of new facilities are under the jurisdiction of state and local government authorities. Because of this, we will carefully consider the views of any state bodies having jurisdiction over these matters. We also will, as discussed below, adopt a rebuttable presumption that projects approved by an appropriate state commission or siting authority are eligible for incentives under section 219. We believe that, in these ways, we will appropriately coordinate our consideration of incentives with the views of responsible state agencies. We will not, however, adopt any further requirements regarding state approval, such as the requirement that an applicant receive state approval of any proposed incentives. While state approval is desirable it is not required by section 219. However, if state approval of a particular plan is required, we expect that any applicant will seek that approval in due course.

55. Finally, we reiterate that an applicant may request any combination of the incentives listed in the Final Rule. Applicants also may request incentives that are not listed in the Final Rule. The Commission will not use the Final Rule to identify each and every incentive an applicant may request. However, this in no way relieves the applicant of fully supporting its rate request and demonstrating that its request for incentives satisfies section 219 and the requirements of this Final Rule. If an interested party

believes a particular incentive is not warranted, it may raise its concerns when an applicant proposes that incentive in a declaratory order or in a section 205 rate application.

56. Because section 219 makes clear that the Final Rule should promote capital investment in the operation and maintenance of all facilities for the transmission of electric energy in interstate commerce, new investment in existing facilities will be eligible for incentive-based rate treatments.[36] The reliability benefits of operation and maintenance capital spending are obvious, and we expect applicants incurring this type of capital spending will be able to demonstrate reliability benefits and thereby be eligible for incentive treatment.

3. Rebuttable Presumptions

57. As we discussed above, we will not adopt the variety of preconditions recommended by the commenters. However, we are nonetheless required to make findings that a particular investment falls within the scope of section 219. In making that finding, we have chosen to rely on existing processes to the extent practicable in determining whether a particular facility is needed to maintain reliability or reduce congestion. We describe these processes below and find that, if an applicant satisfies them, its project will be afforded a rebuttable presumption that it qualifies for

[36] In addition, the Final Rule makes available incentives for joining a Transmission Organization.

transmission incentives. Other applicants not meeting these criteria may nonetheless demonstrate that their project is needed to maintain reliability or reduce congestion by presenting us a factual record that would support such findings. Once we determine that the project is eligible for incentives, we would, as described below, consider whether the particular incentives being proposed are appropriate for the particular investments being made.

58. The first rebuttable presumption we will adopt relates to regional planning. Although we will not require participation in regional planning processes as a precondition for obtaining incentives, as section 219 does not require such a precondition, we believe that regional planning processes can provide an efficient and comprehensive forum through which those seeking to make transmission investments can have their projects evaluated to see if they meet the requirements of section 219. Regional planning processes can help determine whether a given project is needed, whether it is the better solution, and whether it is the most cost-effective option in light of other alternatives (e.g., generation, transmission and demand response). It does so by looking at a variety of options across a large geographic footprint; thus, regional planning can allow for a broad assessment of loop flows and impacts on neighboring systems. Regional Planning also can serve as a forum in which states can readily participate.[37] This benefit of a

[37] State representation in stakeholder committee is a feature of the Midwest ISO, i.e., the Organization of MISO States (MISO States or OMS).

regional planning process is difficult to duplicate on a utility-by-utility basis. It may prove difficult for applicants, on an individual basis, to timely gain access to all the information that might be required to make a showing that the project ensures reliability and/or reduces the cost of delivered power by reducing congestion. The Commission expressly recognized the value of regional planning when it proposed to amend the pro forma Open Access Transmission Tariff of jurisdictional public utilities to require regional planning to ensure that transmission is planned and constructed on a nondiscriminatory basis to support reliable and economic service to all eligible customers in a region.[38] Consistent with our actions in that NOPR and our belief that power markets are regional in nature and that the transmission systems supporting those markets must be supported by regional planning, we will create a rebuttable presumption for projects that result from regional planning. Thus, the Commission will rebuttably presume that transmission projects that result from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found

[38] Preventing Undue Discrimination and Preference in Transmission Service, Notice of Proposed Rulemaking, 71 FR 32,636 (June 6, 2006), FERC Stats. & Regs., Regs. Preambles ¶ 32,603 at P 36 (2006) (OATT Reform NOPR):

> We conclude that the inadequacy of the existing obligation to conduct joint and regional transmission system planning, coupled with the lack of transparency surrounding system planning generally, require reform of the pro forma OATT to ensure that transmission infrastructure is constructed on a nondiscriminatory basis and is otherwise sufficient to support reliable and economic service to all eligible customers.

to be acceptable to the Commission satisfy the requirements of this Rule.[39] In addition, the Commission will adopt the following other rebuttable presumptions. We will also attach a rebuttable presumption that an applicant has met the requirements of section 219 if a proposed project is located in a National Interest Electric Transmission Corridor or where a project has received construction approval from an appropriate state commission or state siting authority.

4. Applicants Seeking Incentive-Based Rates Will Not Be Required To File A Cost-Benefit Analysis

a. Background

59. The NOPR explained that no cost-benefit analysis would be required to obtain incentives because customers will be protected by the Commission's review of applications pursuant to sections 205, 206 and 219 of the FPA, which require that all rates be just and reasonable and not unduly discriminatory or preferential.[40]

b. Comments

60. Certain commenters argue that judicial precedent requires that incentive rates be supported by a showing of a quantifiable relationship between the incentive and the result

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[39] An applicant may wish to file a request for incentive treatment for a project which is undergoing consideration in a regional planning process. The Commission will consider such requests, but may make any requested rate treatment contingent upon the project being approved under the regional planning process. As discussed elsewhere in this Final Rule, different types of projects and the circumstances under which they are undertaken may warrant different rate treatments and incentives.

[40] NOPR at P 16.

the incentive is intended to achieve.[41] They also argue that the level of the incentive must be calibrated to a level that it is no more than needed to achieve the outcome that the incentive is supposed to produce.[42] They further argue that section 219 does not require significant changes to the Commission's existing rules and ratemaking policies governing incentive rates, such as its 1992 Policy Statement[43] and Order No. 2000,[44] in which the Commission required that applications for incentives be supported with cost-benefit analyses. They contend that the Commission's existing rules and policies already satisfy the Commission's obligations under the FPA, even as amended by section 219, and should be retained.[45]

61. Several commenters state that, without a cost-benefit analysis, the Commission has no basis for concluding that a particular incentive provides customers with a net

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[41] E.g., NECOE, PSE&G, and WPC Companies.

[42] E.g., NECOE.

[43] Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities: Policy Statement on Incentive Regulation, 61 FERC ¶ 61,168 at 61,590 (1992).

[44] Regional Transmission Organizations, Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, 65 FR 12,088 (Mar. 8, 2000), FERC Stats. & Regs., Regulations Preambles July 1996-December 2000 ¶ 31,092 (2000), aff'd sub nom. Public Utility District. No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

[45] E.g., TDU Systems, NRECA, NECOE, and SMUD.

benefit or will be just and reasonable.[46] The New York Commission suggests that criteria for a cost-benefit analysis be established through a separate technical conference or rulemaking.

62. PJM argues that the Commission should provide incentives for transmission owners' participation in robust regional transmission planning that identifies both the costs and economic benefits of a given project. PJM proposes that such a process should support a rebuttable presumption that the decision to build is prudent and warrants an ROE incentive.

63. East Texas states that utilities engaged in meeting reliability standards, constructing projects across designated corridors and joining qualified Transmission Organizations should be allowed the incentive rates on the simple showing that they seek to recover no more than their prudently incurred costs. SMUD states that, under section 219, an incentive is appropriate only when it results in lower power costs to consumers. The Oklahoma Commission states that the Commission should give direction as to the showing by applicants that is acceptable in lieu of the cost-benefit analysis.

64. Other commenters argue that a cost-benefit analysis is unnecessary.[47] National Grid states that the Commission already recognized generically the benefits of using ROE

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[46] E.g., NRECA, NARUC, TAPS, East Texas, Connecticut AG, Industrial Customers, NECPUC, California Oversight Board, MISO States, DTE Energy, Wyoming Consumer Advocate, and New York Commission.

[47] E.g., National Grid.

adders as an incentive for needed transmission investment in the Removing Obstacles order.[48] FirstEnergy asserts that consumers benefit by strengthening the transmission grid and by encouraging new investment in transmission and that the benefits of these factors potentially far exceed the costs. International Transmission asserts that requiring a cost-benefit analysis could delay needed transmission upgrades.

c. Commission Determination

65. We reaffirm the NOPR's determination not to require applicants for incentive-based rate treatments to provide cost-benefit analyses. The courts have long recognized that a primary purpose of the FPA, and its counterpart the Natural Gas Act, is to encourage the orderly development of plentiful supplies of electricity and natural gas at reasonable prices.[49] To carry out this purpose, the Commission may consider non-cost factors as well as cost factors.[50] Moreover, Congress's enactment of section 219 reflects its determination that incentives generally can spur transmission investment which will, in turn, provide the benefits of a robust transmission system identified by the

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[48] Removing Obstacles to Increased Electric Generation and Natural Gas Supply in the Western United States, 94 FERC ¶ 61,272, reh'g denied, 95 FERC ¶ 61,225, order on reh'g, 96 FERC ¶ 61,155, further order on reh'g, 97 FERC ¶ 61,024 (2001).

[49] See, e.g., Pub. Utilities Comm'n of the State of California v. FERC, 367 F.3d 925, 929 (D.C. Cir. 2004) (CPUC v. FERC), citing NAACP v. FPC, 425 U.S. 662, 670 (1976).

[50] Id., citing Permian Basin Area Rate Cases, 390 U.S. 747, 791, 815 (1968); Maine Public Utilities Commission v. FERC, No. 05-1001, slip op. at 19 (D.C. Cir., June 30, 2006).

commenters. The Commission will consider the justness and reasonableness of any proposal for incentive rate treatment in individual proceedings.

5. Procedural Requirements for Obtaining Incentive-Based Rate Treatments

a. Background

66. Section 35.35(c) in the NOPR proposed that all rates approved under the rule would be subject to sections 205 and 206 of the FPA. Section 35.35(d) in the NOPR proposed certain options by which an applicant may seek incentive-based rate treatments. The NOPR proposed that applicants must explain whether the proposed facilities are part of an independent regional planning process. The Commission also sought comment on whether the Final Rule should establish a definition of "independent regional planning process" or if the Commission should consider this issue on a case-by-case basis.

b. Comments

67. Most transmission owners request that the Commission implement a streamlined process to review and approve incentive-based rate treatments. For example, some suggest that the Commission adopt a pre-approval procedure that provides a preliminary determination of a project's rate treatment, similar to the expedited pre-approval in the Path 15 upgrade in California,[51] to promote timely construction of additional needed transmission facilities.[52]

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[51] See Western supra note 2.

[52] E.g., Mid-American, Nevada Companies, PacifiCorp, and Northwestern.

68. A number of commenters urge the Commission not to require transmission owners to make section 205 filings to implement incentive-based rates. They argue that such proceedings may result in unreasonable delay and uncertainty and thereby discourage, if not preclude, incentive-based rate proposals.[53] Many of these parties urge the Commission automatically to approve incentives once the facilities or investment have been shown to ensure reliability or reduce congestion.[54] Other commenters suggest that the Commission create a category of incentives that would not require any review under section 205 and then hold paper hearings only for those incentives that do not fall within the designated category of incentives.[55] Other commenters request that the Commission establish a rebuttable presumption that each incentive is just and reasonable or allow transmission owners to self-certify that they meet the criteria of section 219.[56] Others similarly ask that there be a presumption that facilities included in a regional planning process are eligible for incentives.[57] Another group of commenters argue that projects

[53] E.g., United Illuminating, Vectren, NSTAR, and EEI.

[54] E.g., Nevada Companies and MidAmerican.

[55] E.g., EEI, NU, New England TOs, NYSEG, and RGE.

[56] E.g., Southern and FirstEnergy.

[57] E.g., BG&E, PEPCO, KCPL, National Grid, PJM, PJM TOs, United Illuminating and Vectren.

need not be part of an independent regional planning process to receive an incentive because other regional processes will also provide the same benefits.[58]

69. EEI argues that public utilities should be permitted to make limited section 205 filings to specifically address recovery of incentives in rates, regardless of the form of rate.

70. National Grid requests clarification that the Commission will continue to accept incentive and rate reforms that are tailored to the specific needs of the transmission owner, so that transmission owners can be allowed more traditional rate treatment, such as accruing the allowance for funds used during construction, capitalization of pre-commercial costs and a 30-year depreciation.

71. BG&E requests clarification that, once the Commission approves an incentive-based ROE for a particular regional planning process, any entity within that planning process will be authorized to receive the approved incentive-based ROE without being required to individually apply for, or rejustify, the incentive.

72. Some commenters argue that the Commission must review all elements of an applicant's cost of service before authorizing any incentives.[59] The Steel Manufacturers assert that applicants must justify each incentive they request under sections 205, 206,

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[58] E.g., EEI, Progress, Nevada Companies and FirstEnergy.

[59] E.g., Dairyland, TDU Systems, and NASUCA.

and 219 and that those applications seeking more than one incentive must demonstrate that the overall package results in rates that satisfy the same criteria.

73. TAPS asserts that, when an applicant files a facility-specific incentive filing the load divisor and depreciation reserve should be updated, in the circumstance that existing rate inputs are known; and, if they are not known because they are part of a "black box" settlement, they should be imputed. TAPS suggests ways in which this can be done.

74. Snohomish argues that applicants should be required to submit a schedule of lower-cost alternatives, including potential non-wires solutions, and to explain why these alternatives were not chosen. The Oklahoma Commission recommends that state commissions make the determination as to whether the cost of the project, including the cost of the incentive, is more beneficial for ratepayers than if a generation facility were built closer to avoid the cost of transmission.

75. Finally, several commenters urge the Commission to adopt a generic definition of independent regional planning as well as guidelines and minimum criteria for acceptable independent regional planning processes.[60] Other commenters ask the Commission to be flexible in determining what constitutes a satisfactory "regional planning process," and to take into consideration any differences among regions on a case-by-case basis.[61]

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[60] E.g., PJM TOs, APPA, International Transmission, MidAmerican, Pacificorp, National Grid, Kentucky Commission, PJM, OMS, NRECA and Semantic.

[61] E.g., Consumer Energy Council, Ameren, SDG&E, Southern Companies, NorthWestern and PEPCO, Dairyland, and Vectren.

c. **Commission Determination**

76. Our goal is to provide procedural options that offer applicants flexibility to address their construction and investment opportunities while at the same time ensuring that the resulting rates are just and reasonable and not unduly discriminatory or preferential. The Commission offers two ways to accomplish this. An applicant may obtain these rulings: (1) through a combination of a petition for a declaratory order and a subsequent section 205 filing or (2) by filing only a section 205 filing. For both of these options, the applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219, that there is a nexus between the incentive sought and the investment being made, and that the resulting rates are just and reasonable.

77. The Commission has found that the first option – petition for declaratory order followed by a section 205 filing – to be a valuable tool. In certain instances, it is valuable for an applicant to obtain an order indicating it qualifies for incentive-based rates prior to making a formal section 205 filing and prior to commencing siting, permitting and construction activities because such orders facilitate financing and investment in new facilities.[62] To provide applicants with as much flexibility as possible, the Commission will permit applicants to seek a declaratory order prior to construction of the facilities to

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[62] See Western supra note 2.

request a finding that the facilities qualify for incentive-based rate treatments. The petitioner would have to demonstrate that its proposal will either ensure reliability or reduce the cost of delivered power by reducing transmission congestion. The petitioner may rely on one of the rebuttable presumptions outlined above or make an independent demonstration. The applicant may also use the petition to justify which incentives it seeks to implement. We clarify that any declaratory order will only rule on whether the applicant's proposal qualifies for incentive-based rate treatment and, if requested, which incentives the applicant may adopt. The applicant must seek to put the rates into effect through a separate single-issue or comprehensive section 205 filing. The Commission's expectation is that, based on past practice, a declaratory order finding that the applicant is eligible for incentive-based rate treatments would be sufficient for the applicant to obtain funding or otherwise acquire financing for the project. The Commission will seek to process petitions for declaratory order quickly. While we cannot guarantee Commission action within 60 days of the request (as is statutorily required for section 205 filings), we will strive to meet that standard.

78. If an applicant obtains a declaratory order finding that the proposal qualifies for incentive-based rate treatment, the subsequent section 205 proceeding would be limited to a review of the applicant's rates and would not include a review of whether the applicant's facility qualifies to receive incentive-based rate treatments. If the petition addresses the applicant's incentives or finds that the required nexus has been demonstrated, the applicant would not be required to re-justify those findings in the

section 205 filing. Therefore, if an interested party believes a petitioner's proposal does not qualify for incentive-based rate treatments or that the incentives requested are not justified, the party must raise its objections when the petition is filed and not wait to raise them in the subsequent section 205 proceeding. If an applicant obtains a declaratory order and the proposal changes from the facts on which the declaratory order was issued, the applicant may seek another declaratory order or wait to seek approval of the changes in the subsequent section 205 filing. In that event, interested parties may challenge the changes in the section 205 proceeding.

79. The second option involves filing only a section 205 filing (either "single-issue" or comprehensive) to request all of the required approvals. Prior to recovering any incentive-based rate treatments in rates, an applicant must demonstrate that the rates in which the applicant seeks to recover any incentives are just and reasonable and not unduly discriminatory. However, the applicant will have the option of filing a comprehensive section 205 rate case in which all of the utility's rates would be reviewed in conjunction with the proposed recovery of the incentive-based rate treatments or filing a single-issue section 205 rate filing in which only the impact of the incentive-based rate treatment for the facility granted the incentive will be addressed. As explained below in section IV.B.7 (the discussion of single-issue section 205 proceedings), the Commission believes there is a sufficient need for timely investment in transmission infrastructure to justify, in certain circumstances, a departure from our past practice by allowing an applicant to seek to recover any incentive in a single-issue section 205 rate proceeding.

Single issue section 205 proceedings, as well as the declaratory order procedural option discussed above, can remove obstacles to new investments by allowing for timely cost recovery. Single issue filings also can support new investment by allowing applicants to compare the returns of such investments with the risks of the project itself, as opposed to having to compare those returns to both the risks of the project being pursued <u>and</u> the risks associated with re-opening all their rates, which is ordinarily a time-consuming, expensive, litigious and uncertain process. Additionally, in further facilitating these goals, the Commission does not intend to routinely convene trial-type, evidentiary hearings to review either a comprehensive or a single-issue section 205 filing but will attempt to render a decision based on the paper submissions whenever possible.

80. We clarify that no incentives will be granted on a final basis without a section 205 filing. Therefore, an RTO member will not automatically receive incentives granted to another RTO member. However, when evaluating applications for incentive-based rate treatments filed by an RTO member, the Commission will take into account incentives granted to other RTO members, particularly in cases where investments being made by that other RTO member pursuant to a regional plan also lead to the need for expansions by the applicant in its own footprint.

81. We will not specify the rate calculations for section 205 proceedings, as requested by TAPS. These issues are appropriately addressed in individual section 205 proceedings.

82. The Commission will require applicants to justify each of the incentive-based rate

treatments it proposes by showing how the proposed incentive satisfies section 219.[63] For example, an applicant will be required to show how the granting of the incentive will promote reliable and economically efficient transmission and generation of electricity, attract new investment, or increase capacity and efficiency of existing transmission facilities or improve their operation. The Commission, as set forth above, provides several vehicles for making this showing, including reliance on a Commission accepted regional planning process. We also will require the applicant to show that there is a nexus between the incentives being proposed and the investment being made.

83. With respect to procedures applicable to joining Transmission Organizations in § 35.35(e), we clarify that applicants also may file a petition for declaratory order as to whether the applicant qualifies for incentives under section 219(c) and then submit a comprehensive or single-issue section 205 filing to obtain approval of the rates, or simply file a comprehensive or single-issue section 205 case to obtain all necessary approvals.

B. Incentives Available To All Jurisdictional Public Utilities

84. In the NOPR, the Commission proposed eight incentive-based rate treatments for transmission infrastructure investments for all public utilities, including Transcos. As discussed below, the Commission will adopt these in the Final Rule.

[63] An applicant would not be required to demonstrate that, but for the incentive, the project would not be completed. Section 219 does not require such a condition.

1. ROE Sufficient to Attract Capital

a. ROE

i. Background

85. The Commission proposed to consider granting an incentive-based ROE to all public utilities (i.e., traditional public utilities and Transcos) that build new transmission facilities that benefit consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion thereby fulfilling the requirements of section 219. As proposed, to receive an incentive-based ROE, a public utility must submit a request in an application under section 205 of the FPA and must support the ROE request by demonstrating how the new facilities will improve regional reliability and reduce transmission congestion. In addition, the application must explain whether the facilities are part of an independent regional planning process, such as that administered by an RTO or ISO or another independent regional planning process recognized by the Commission and how the proposed ROE was derived and why it is appropriate to encourage new investment. (NOPR at P 22) Recognizing that the Commission had approved higher ROEs (referred to in the NOPR as an "adder") for certain projects that were designed to increase transfer capability or reduce congestion, the Commission sought comments on the appropriateness of a higher ROE as a mechanism for increasing investment in new capacity.

ii. Comments

86. Numerous Commenters[64] express general support for the proposal to grant incentive-based ROEs to encourage transmission investment stating that it is the most direct and effective means of attracting needed capital to improve the nation's transmission infrastructure. Southern Companies assert that allowing an incentive ROE only "within the zone of reasonableness" is inconsistent with Congress' mandate in section 219 that the Commission provide incentive ROEs for transmission investment. NSTAR and Vectren state that an incentive need not be cost-based; an incentive is justified under the statute as just and reasonable if it serves the statutory purpose of improving reliability or reducing the overall cost of delivered power.

87. Other commenters oppose the Commission's proposal to grant incentive-based ROEs for investment in new transmission facilities. For example, APPA states that an ROE adder is basically a bonus payment to reward transmission providers for doing the job for which they are already getting paid an adequate ROE under current Commission standards and relevant FPA requirements. Connecticut DPUC argues ROE adders are not a useful policy tool for improving transmission and the Commission's standard rate review process of assessing the firm's risk-adjusted cost of capital assures a completely adequate ROE without any adders. TDU Systems and New Mexico AG contend that

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[64] E.g., National Grid, FirstEnergy, EEI, KCPL, Xcel, Kentucky Commission, Nevada Companies, Progress, and Southern Companies.

ROE adders will fail the judicial mandate that rates be just and reasonable. CREPC maintains that a blanket ROE increase generally runs counter to the Commission's goal of encouraging transmission investment because it will either unnecessarily increase the cost of electricity to end-users or render an otherwise economic transmission project uneconomic in comparison to its alternatives. The California Commission states that the Commission's reliance on incentives granted to Trans-Elect with respect to financing the critical Path 15 upgrade in California several years ago is misleading since the special consideration accorded to Trans-Elect was a direct consequence of the unique, emergency energy crisis facing California and the Western United States in 2001.

88. Some commenters[65] assert that the Commission must consider the certainty of rate recovery for investment in new transmission facilities and associated lower risk -- providing the basis for a lower ROE -- before granting incentive-based ROEs. Others, however, such as MidAmerican and PacifiCorp, state that the Commission should consider ROE adders or other forms of enhanced returns if a project investment entails levels of risk to investors and consumers that a traditional rate of return would not cover or otherwise lacks the economic or commercial incentives necessary to attract needed capital. PJM recommends the Commission establish an equity return range based on a generic analysis of investor expectations concerning transmission investment as opposed

[65] E.g., NRECA, CREPC, AWEA, the Delaware Commission, New Mexico AG, NY Association, the New York Commission, the California Commission and SMUD.

to an analysis of a vertically integrated company or, as an alternative, recognize the overall risk of each project, such as the risk of delayed recovery at the state level.

89. TAPS states that any incentive-based adjustment to transmission returns should take the form of an equivalent adjustment to total return (i.e., return on both debt and equity), rather than making the value of the adjustment vary with the transmitter's capital structure. TDU Systems state that if the Commission allows ROE adders, it should consider applying the adders to the overall rate of return as an alternative to estimating equity returns using public utility returns as a proxy.

90. MISO States argues that the Commission should make clear that proposed ROE incentives are on investments in new transmission, as contrasted with all of a public utility's transmission investment. TAPS claims that increasing the ROE for existing facilities does nothing to encourage investment in new transmission facilities. TDU Systems recommends limiting ROE adders to the portion of rate base related to the new investment.

iii. Commission Determination

91. Consistent with the proposal in the NOPR, the Commission will allow, when justified, an incentive-based ROE to all public utilities (i.e., traditional public utilities and Transcos) for new investments in transmission facilities that benefit consumers by ensuring reliability or reducing the cost of delivered power by reducing transmission congestion. By including this provision in the Final Rule, we meet the requirement of section 219 to provide an ROE that attracts new investment in transmission facilities

(including related transmission technologies). Public utilities making investments in transmission infrastructure have made clear, both in their applications for new projects and in their comments on this Rule, that the ROE incentives encourage investment. We expect that an incentive ROE will make transmission projects more attractive, and therefore more likely, when transmission projects must compete for capital in vertically-integrated utilities as well as in transmission and delivery utilities. Accordingly, the Commission will approve an ROE at the upper end of the zone of reasonableness for new infrastructure investments that meet the requirements of section 219 as discussed elsewhere in this Final Rule.

92. Concerns of blanket ROE increases and ROEs that exceed the DCF determined ROE are misplaced. The NOPR's use of the term "adder" may have contributed some confusion regarding the Commission's proposal. The Commission, as discussed later in this section, will continue to use the DCF analysis for ROE determinations. That analysis can result in a range of returns (e.g., 9 percent to 13 percent), any of which falling within the range are just and reasonable. This analysis, undertaken in individual rate applications, assesses representative proxy companies and the impact of other factors, including risk, on the zone of reasonableness for ROE. Thus, contrary to certain comments, our justification for a higher ROE is not based on a risk assessment; the risk assessment is part of the traditional DCF analysis.

93. Under the Rule adopted herein, the Commission will provide ROEs at the upper end of the zone of reasonableness for transmission investments that meet the

requirements of section 219 as discussed elsewhere in this Final Rule. Incentive-based ROEs, like other incentives offered in this Rule, are to be filed with the Commission for approval before rates that reflect such incentives can be charged. Accordingly, because the approved ROE, including the impact of an incentive, will be within the zone of reasonableness, we consider this provision consistent with section 205 of the FPA. We will not create specific ROE adders (e.g., 100 basis points); the Commission has always considered a range of returns in determining the appropriate ROE and we see no reason to depart from this practice. Though some commenters assert that the incentive need not be cost-based and therefore can justifiably be above the upper-end of the zone of reasonableness, we believe a return within the zone will be adequate to attract new investment and consistent with the intent of Congress in section 219. The Commission will determine the level of the ROE on a case-by-case basis when an application for an incentive-based ROE is filed with the Commission. This is consistent with the approach the Commission has employed to date, which has been found to be just and reasonable.[66]

94. The foregoing does not mean, however, that we will grant incentive-based ROEs to every new investment that increases reliability or reduces congestion. The purpose of section 219 was, as described above, to require the Commission to re-examine whether its current policies are adequate to encourage new investment and strike the appropriate

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[66] Public Utilities Commission of the State of California v. FERC, 367 F.3d 925 (D.C. Cir. 2004).

balance between the investor and consumer interests. In many instances, an incentive-based ROE is appropriate because our traditional policies are not sufficient to encourage new investment. For example, a large new interstate transmission project that reduces congestion or increases reliability can face substantial risks that the ordinary transmission investment does not. Further, such projects will often be undertaken only at the election of investors, given that no single entity is "required" to undertake them, and thus an incentive-based ROE is appropriate to encourage proactive behavior. Other projects also may present special risks or considerations that merit an incentive-based ROE. By contrast, there are certain projects that may not merit such an incentive. For example, routine investments made to comply with existing reliability standards may not always qualify for an incentive-based ROE. These are the types of investments that have, as a general matter, been adequately addressed through traditional ratemaking because there is an obligation to construct them and high assurance of recovery of the related costs. For these and other reasons, traditional ROE determinations may continue to be appropriate for these investments. This does not mean that other incentives may not be appropriate for such investments (such as 100 percent CWIP recovery) or that other reliability investments (e.g., substantial new investments to meet new standards) would not qualify for incentive-based ROE determinations.

95. We decline to apply incentives to total return, including debt, as requested by TAPS. Section 219 directs the Commission to focus on ROE, not total return; and this focus is proper. In a competitive market for debt financing, any incentives added to the

actual costs of debt will flow to equity investors without actually increasing the returns of debt capital providers. Unlike debt investors who do not propose new investment or make direct investment decisions, equity investors make investment decisions directly or by giving management their proxy. Thus the opportunity for a higher ROE will directly and more transparently influence the actions of those in the position to make initial investment decisions.

96. With regard to questions about whether the opportunity to earn an incentive-based ROE applies to all of a public utility's transmission investment, we clarify that it applies to new transmission investment including investment that results in the enlargement of or improved operation and maintenance of all facilities, consistent with section 219 as discussed elsewhere in this Final Rule.

b. Alternatives to DCF Analysis

i. Background

97. While the Commission has typically utilized a DCF analysis, the NOPR (at P 20) sought comment on whether it should consider alternatives to the DCF analysis as a way to provide incentives for investment in new transmission capacity.

ii. Comments

98. A number of commenters[67] do not support a departure from the DCF method that the Commission currently uses to determine allowed ROE. APPA , for example, states

[67] E.g., APPA, the Kentucky Commission, New Mexico AG, NY Association, New York Commission, TDU Systems and TAPS.

that the DCF approach is generally analytically sound and has produced consistent, predictable results over time, eliminating some of the subjectivity and randomness in equity forecasts that might occur if the Commission were to change methods on a case-by-case basis. The New York Commission supports the use of a DCF analysis as an appropriate means to determine an ROE that reflects commensurate risks and thus would attract new investments.

99. A number of commenters,[68] request that the Commission adopt additional methodologies, such as risk premium, comparable earnings, Fama-French, and/or capital asset pricing, to use along with the current DCF analysis because a multiple model approach will result in a more representative ROE range. These commenters contend that the Commission should make clear that it will consider and use alternative methods of calculating ROEs. They argue that the Commission's final determination of a just and reasonable ROE should be based on a combination of the results from those alternative methods of calculating ROEs, not on the result from any single method, because each method has its own set of theoretical deficiencies and a range of methods ensures all applicable variables are considered.

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[68] E.g., AEP, Ameren, EEI, California Commission, KCPL, PacifiCorp, PEPCO, PJM TOs, Progress Energy, NSTAR, SDG&E, SCE, Southern Companies, Trans-Elect, Vectren and WPS.

100. Other Commenters[69] ask that the Commission consider changes to how it determines proxy groups in the DCF analysis, by permitting adjustments for leveraging effects, or adopting modified or expanded proxy groups, as appropriate on a case-by-case basis, and by looking more to companies in the primary or sole business of providing electric delivery service or by isolating those activities from the other activities of public utilities included in proxy groups. EEI recommends that the Commission should use after-tax weighted average cost of capital to adjust for leverage differences among sample companies and recommends applying DCF results to the market value of equity rather than to the book value of equity.

101. NSTAR and New England TOs assert that any changes to the Commission's ROE methodology should not be considered an incentive because updating the ROE methodology including appropriate recognition of risk is not an incentive, but rather is necessary to assure that the ROEs received by transmission-owning utilities are compensatory and fair under current market conditions and recover their cost of capital.

iii. <u>Commission Determination</u>

102. While commenters note that every alternative method has a theoretical deficiency and there is a benefit to introducing more information into the analysis process, we do not see any basis to conclude that the alternative methods would encourage more transmission investment than continued reliance on the DCF analysis. Our past practice

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[69] <u>E.g.</u>, PEPCO, APPA, PJM, AEP, FirstEnergy, and Ameren.

of using the DCF approach has yielded just and reasonable results and is consistent with long-standing ratemaking principles. Therefore, at this time, we will not make broadly applicable changes to how the Commission has traditionally performed its DCF analysis on companies in the electric industry. However, we will consider on a case-by-case basis whether the application of the traditional DCF analysis should be modified and entertain proposals to use different proxy groups as a way of capturing different business models.

2. Construction Work in Progress (CWIP) and Pre-Commercial Expenses

a. Background

103. In the NOPR, the Commission noted that the long lead times required to plan and construct new transmission can impact utility cash flow, in turn affecting the overall financial health of a company and its ability to attract capital at reasonable prices. The Commission proposed including 100 percent of CWIP in rate base;[70] and expensing rather than capitalizing pre-commercial operations costs associated with new transmission investment in order to relieve the pressures on utility cash flows associated with transmission investment programs.

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[70] CWIP is a return on capital. Since 1987, the Commission's general policy has been to allow only 50 percent of the non-pollution control/fuel conversion construction costs as CWIP in rate base. The remaining construction costs, including an allowance for funds used during construction (AFUDC) which provides a return on those expenditures, generally would have been capitalized and included in rate base only when the plant went into commercial operation, i.e., when the plant became used and useful. Allowing some portion of the costs in rate base prior to commercial operation provides utilities with additional cash flow in the form of an immediate earned return. See 18 CFR 35.25(c)(3).

104. In 2004, the Commission accepted a proposal by American Transmission Company (American Transmission) to include 100 percent of CWIP in the calculation of transmission rates and to expense pre-commercial operations costs for new transmission investment, instead of capitalizing those costs and earning a return.[71] American Transmission stated that these incentives would help maintain adequate cash flow during the construction process and that without these incentives it could face a downgrade of its fixed income rating over the next several years due to inadequate cash flow, thereby increasing its capital costs by $176 million over a twenty-year horizon.

105. The Commission stated in the NOPR that allowing public utilities, on a case-by-case basis, to include up to 100 percent of prudently incurred transmission-related CWIP in rate base and permitting them to expense prudently incurred pre-commercial operations costs will further the goals of section 219 by relieving the pressures on utility cash flows associated with their transmission investment programs and providing up-front regulatory certainty. The Commission specifically requested comment on (1) the types of costs that should be considered "pre-commercial" operation costs; and (2) whether there should be a presumption that these incentives meet the requirements of FPA section 219 that investments ensure reliability and reduce the cost of delivered power.

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[71] See American Transmission, supra note 2.

b. <u>Comments</u>

106. Most of the commenters,[72] support including 100 percent of prudently-incurred CWIP in rate base and expensing all pre-commercial operation costs, stating that these incentives will encourage transmission investment through improved cash flow, greater rate stability and lower rates to future customers. Additionally, SDG&E notes that this incentive will balance short-term rates and long-term rates by increasing the rates during construction but lowering the rates during operation of a facility.

107. Opponents, such as the New Mexico AG and California Commission, state that maintaining the status quo would be in keeping with the long-standing ratemaking doctrine that recovery of utility plant costs should be based on utility plant that is "used and useful." They also oppose expensing pre-commercial costs instead of capitalizing such costs because there will be no opportunity for a comprehensive review of project costs before those costs are passed on to ratepayers.

108. Snohomish argues that the Commission must implement a procedure to handle refunds where the project is never ultimately completed, and must condition inclusion of CWIP and other pre-operation costs in rates on adherence to the construction schedule submitted with the application.

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[72] <u>E.g.</u>, EEI, American Transmission, AWEA, PG&E, AEP, NSTAR, WPS and TDU Systems.

109. In its supplemental comments, EEI recommends the Commission waive the requirement that a utility requesting CWIP must provide a forward-looking allocation that estimates the average use a wholesale customer will make of the utility system over the life of a project, as currently required by 18 CFR 35.25(c)(4). EEI states the purpose of the required forward-looking allocation is to protect wholesale customers against a double whammy (i.e., being required to pay for the construction of new generation facilities if the customer switched supplier). EEI states that the double whammy concern is not present with transmission facilities because the customer will almost certainly not switch transmission suppliers.

110. TDU Systems assert that CWIP should not be allowed for projects for which the public utility receives upfront interconnection payments, nor for any project for which the funds have been provided by a third party, except in tandem with crediting-back of such prepayments or investments on a schedule to which the transmission customer agrees. TDU Systems assert that if formula rates are in place for the public utility seeking to expense the cost of capital assets, inter-generational inequity is even more egregious since the public utility may well receive a one-year amortization of that expense although future rate payers will benefit from the use of those facilities for years to come.

111. Other commenters state that pre-commercial costs should be defined and the Commission should provide guidance.[73] Commenters' proposals for pre-commercial costs definitions include all costs associated with pre-construction activities, such as planning, related studies, and siting costs, including (1) costs of routing studies for placement of transmission lines, (2) costs of certification associated with regulatory approvals including legal and consulting costs, (3) costs of public hearings and informational hearings, (4) costs for design, planning, drafting, surveying services, material procurement and labor in support of project construction, and (5) costs associated with development and implementation of interim measures to maintain adequate reliability level due to the delayed completion of the proposed project.

112. Additionally, EEI argues the Commission should also include as pre-commercial costs other costs that have been traditionally expensed such as costs of resetting relays, using a mobile transformer, making payments to other transmission owners for upgrades to their lines, and the write-offs of the undepreciated cost of facilities that are being replaced with new transmission investment.

113. NRECA states that these costs should be limited to prudently incurred direct transmission investment costs. TDU Systems states that in no event should the

[73] E.g., EEI, SCE, AEP, NSTAR, WPS, NU, FirstEnergy, the Nevada Companies, KCPL, NRECA and Ameren.

Commission allow public utilities to expense costs associated with transmission facilities such as land, towers, transformers, lines, and substations.

114. PJM recommends that costs of developing a transmission proposal through a planning process should be considered a pre-commercial cost.

c. Commission Determination

115. After considering all the comments, we adopt in this Final Rule the proposal from the NOPR to give public utilities, where appropriate, the ability to include 100 percent of prudently incurred transmission-related CWIP in rate base and to expense prudently incurred "pre-commercial" costs. These rate treatments will further the goals of section 219 by providing up-front regulatory certainty, rate stability and improved cash flow for applicants thereby easing the pressures on their finances caused by transmission development programs. As noted by many commenters, these proved effective for American Transmission by easing the pressures on American Transmission's finances caused by its transmission development program allowing American Transmission to, among other things, stay on schedule with its development program. For American Transmission, this also meant a higher credit rating and lower cost of capital, thus benefiting customers. Similar results can be expected for other transmission developers availing themselves of such opportunities.

116. We appreciate the concerns, as expressed by the California Commission and others, that the proposal is a departure from existing ratemaking doctrine that rates should be based on plant that is "used and useful." However, as times and circumstances

warrant, the Commission has revised its ratemaking policies. In fact in Order No. 298,[74] the Commission did just that when it decided to allow any public utility engaged in the sale of electric power for resale to file to include in rate base up to 50 percent of CWIP, subject to limitations. Thus, the Commission already allows inclusion of some CWIP in rate base. The Commission also departed from existing principles in the American Transmission and Southern California Edison cases.[75] The nation has suffered a decline 0in transmission investment and it is time that the Commission revisit ratemaking policies that may serve as a barrier to investment and revise them accordingly while ensuring that customers are protected and rates remain just and reasonable. Finally, we note that 100 percent recovery of CWIP costs is already provided for pollution control facilities of public utilities.[76]

117. Allowing public utilities the opportunity, in appropriate situations, to include 100 percent of CWIP in the calculation of transmission rates and to expense pre-commercial operations costs for new transmission investment (instead of capitalizing these costs and earning a return) removes a disincentive to construction of transmission, which can

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[74] Construction Work in Progress for Public Utilities; Inclusion of Costs in Rate Base, Order No. 298, FERC Stats. & Regs. ¶ 30,455 (1983), order on reh'g, 25 FERC ¶ 61,023 (1983).

[75] See American Transmission, supra note 2; Southern California Edison Co., 112 FERC ¶ 61,014, at P 61, reh'g denied, 113 FERC ¶ 61,143 (2005) (SCE).

[76] See 18 CFR 35.25(c)(1).

involve very long lead times and considerable risk to the utility that the project may not go forward. The fact that public utilities have the opportunity to recover these costs in rates in a different manner than in the past does not mean that the rates are not subject to review under FPA sections 205 and 206. Even for rates that are formulaic, it may be necessary for the utility to revise the rate formula under section 205 to capture the recovery of these types of costs to the extent that they are not provided for in the formula. Moreover, as the D.C. Circuit has found, the Commission can depart from the norm as long as it reasonably balances consumers' interest in fair rates against investors' interest in "maintaining financial integrity and access to capital markets."[77] Finally, if the transmission facility never enters service (i.e., is never used or useful), the transmission owner may still seek recovery of the expenses associated with the construction work in progress (i.e., the return on capital) under our abandoned plant incentive, as discussed below. Accordingly, we find that the "used and useful" ratemaking principle is not a sufficient basis to deny adoption of the NOPR's proposal. However, as explained above, we will require each applicant to demonstrate that there is a nexus between its request for

[77] Jersey Central Power & Light Co. v. FERC, 810 F.2d 1168, 1178 (D.C. Cir. 1987) (Jersey Central). "Although a utility's rate base normally consists only of items presently "used and useful" (see New England Power Co. Mun. Rate Comm. v. FERC, 668 F.2d 1327, 1333 (D.C. Cir. 1981), cert. denied, 457 U.S. 1117 (1982)), a utility may include "prudent but canceled investments" in its rate base as long as the Commission reasonably balances consumers' interest in fair rates against investors' interest in "maintaining financial integrity and access to capital markets." Jersey Central, 810 F.2d 1168, 1178 (D.C. Cir. 1987).

100 percent CWIP recovery and the investments being made. Ordinarily, such an incentive would be appropriate for large new investments or in situations, as occurred with ATC, where denying such an incentive would adversely affect the utility's ratings. There may be other situations as well where such an incentive is appropriate and we will consider each proposal on the basis of the particular facts of the case.

118. With regard to requests that the Commission condition inclusion of CWIP and pre-operation costs on adherence to the construction schedule submitted with the application and that we implement a procedure to handle refunds in the event the facility is not put into service, we find them to be unnecessary and/or inconsistent with the other measures we adopt in this Final Rule. As discussed further below, the Commission is proposing to provide a public utility with the opportunity to file for abandoned plant costs. Thus, requiring a refund procedure that raises perceived risks of proposing new transmission at this time would be inconsistent. We also do not see the need to condition inclusion of CWIP on adherence to a construction schedule. Because the actual recovery of CWIP will occur either under a rate on file or a rate to be filed under FPA section 205, parties will have an opportunity to raise any concerns with regard to actual expenditures vis-a-vis construction progress at that time. Accordingly, we see no reason to condition inclusion of CWIP on adherence to a construction schedule.

119. The Commission’s current CWIP regulations were developed in an era of bundled wholesale services and apply to any rate schedule. Since that time, most wholesale transmission service subject to the Commission’s jurisdiction is provided at unbundled

rates under open access transmission tariffs. EEI points out that the requirement for a forward looking allocation that estimates the average use a wholesale customer will make of the utility system over the life of the project is not necessary with transmission facilities. We agree. The forward looking allocation ratio was to prevent a customer that was switching power plant suppliers from having to share in the cost of CWIP of a particular plant if the customer had no responsibility in the decision of the utility to build the plant. We believe it highly unlikely that transmission customers will be faced with such an opportunity. Accordingly, because we do not view the "double whammy" to be a concern in the transmission context, we grant EEI's request and waive the requirement in 18 CFR 35.25(c)(4) as it pertains to preventing double whammy with regard to CWIP associated with new investment in transmission.[78] Further, we clarify § 35.35(d)(1)(ii) to state that other provisions of § 35.25 apply, unless waived by the Commission on a case-by-case basis. We believe that these clarifications to the regulatory text will avoid uncertainty expressed by commenters regarding the procedures for obtaining the CWIP incentive.

120. In response to comments, we clarify that pre-payments, i.e., payments prior to the start of construction, for project costs by third-parties should not be included in CWIP. If

[78] However, this waiver does not relieve transmission owners from supplying the necessary information required in § 35.25(c) (4) that pertains to CWIP-induced price squeeze. The Commission will evaluate CWIP-induced price squeeze concerns on a case-by-case basis.

a customer is making contributions in aid of construction, these amounts should not be included in rate base. Similarly, in the instance of generator interconnect, the up-front amount paid by the customer should not be included in rate base; rather it is included in rate base over time as the transmission provider provides credits to the customer.

121. The Commission has previously determined that recovery of CWIP on a formulary basis is not permitted without prior Commission review to ensure that the Commission's CWIP standards are met.[79] The Commission in Maine Yankee allowed Maine Yankee to propose a method to limit its filing obligation to once a year so that Maine Yankee did not have to file each month that it changed the CWIP balances in its monthly formula charges.[80] Likewise, we will allow public utilities to propose a method to limit their filing requirement related to CWIP to an annual filing. These annual filings may be limited to CWIP and will not subject public utilities to a comprehensive rate review.[81]

[79] Maine Yankee Atomic Power Co., 66 FERC ¶ 61,375, at 62,252-53 & n.10 (1994) (Maine Yankee).

[80] Id., at 62,252.

[81] We deny the request to limit recovery of these incentives to the amount originally budgeted. We note that, as a practical matter, it would be difficult to hold electric transmission projects to the original budget estimate when it can be 10 to 15 years between the time the project is proposed and lines are actually built. Also, if public utilities are held to recovering only originally estimated budgets, they would either have incentives to overestimate costs or to avoid the risky projects which the policy is intended to facilitate.

122. With respect to the types of pre-commercial operations costs that we will allow to be expensed rather than capitalized, we will allow, on a generic basis, the same types of costs that we approved in the American Transmission settlement.[82] Further, we will entertain proposals by public utilities to expense other types of costs for consideration on a case-by-case basis.

3. Hypothetical Capital Structure

a. Background

123. The Commission stated in the NOPR (at P 29) that it has largely relied on the actual capitalization of a utility in setting its rate of return, but recognized that an overly rigid approach to evaluating a proposed capital structure could be a disincentive to investment in new transmission projects and Transco formation. Each project or company may have unique financial and cash flow requirements, and a rigid approach to acceptable capital structures could threaten the viability of some projects. Accordingly, the Commission proposed allowing applicants to file an overall rate of return based on a hypothetical capital structure, and giving them the flexibility to refinance or employ different capitalizations as may be needed to maintain the viability of new capacity additions. The Commission stated that it expected applicants to develop their proposals

[82] American Transmission, in its application approved in American Transmission defined pre-certification costs as preliminary survey and investigation costs in Account 183. These costs include all expenditures for, preliminary surveys, plans and investigations, made for the purpose of determining the feasibility of utility projects and costs of studies and analyses mandated by regulatory bodies related to plant in service.

based on the specific requirements and circumstances of their projects, and that the Commission would evaluate proposals for this incentive on a case-by-case basis. The Commission required public utilities to provide support in their application for why the hypothetical capital structure incentive is needed to promote investment consistent with the goals of section 219. The Commission required the applicant to provide its transmission investment plan and explain the specific projects to which the proposed return will apply.

b. Comments

124. Many commenters support the hypothetical capital structure as an incentive.[83] Both American Transmission and Trans-Elect note that they received approval to use a hypothetical capital structure and that they had been able to stay on schedule for extensive transmission construction programs. [84]

125. Several parties, including EEI, NSTAR and NU argue in a similar vein that hypothetical capital structures can aid investments by companies that are entering a large capital expenditure program or are emerging from financial distress and may be aiming

[83] American Transmission, EEI, First Energy, KCPL, Nevada Companies, NSTAR, NU, NYSEG and RGE, PJM, PG&E, Progress, Semantic, Trans-Elect, United Illuminating and Xcel support the proposal.

[84] Trans-Elect cites Western, 99 FERC ¶ 61,306 at 62,280, reh'g denied, 100 FERC ¶ 61,331 at P 7, 9 (stating that rate treatments including hypothetical capital structure were necessary for the Path 15 project to be built). See also, METC, 105 FERC ¶ 61,214 at P 20 (Commission recognized the need to encourage, through regulatory rate-making policy, the independent business model).

for a capital structure they have not yet realized. Semantic suggests a 75 percent equity and 25 percent debt capital structure be used to reflect the higher risks of early adoption of advanced technologies.

126. PJM and NSTAR state that hypothetical capital structures are particularly useful for projects involving consortia. PJM cites its proposed consortium approach to building transmission, where a capital structure could be based on the project as a whole rather than piecemeal based on the individual capital structures of each participant in individual rate cases.[85]

127. A number of commenters oppose hypothetical capital structures.[86] APPA and CREPC argue hypothetical capital structures could result in a windfall to public utilities by increasing actual return far in excess of the Commission's allowed return on equity. Commenters also express concern that the proposed incentive represents a departure from Commission precedent and could result in unjust and unreasonable rates.

128. Other commenters, such as the Kentucky Commission, Dairyland and MISO States, assert that the Commission should preclude a public utility from receiving both hypothetical capital structure and the ROE incentive because combining the incentives

[85] PJM TOs concur that the incentive could be helpful in project-specific rates.

[86] E.g., California Commission, TDU Systems, APPA, CREPC, Steel Manufacturers, New Mexico AG, the Oklahoma Commission, PPC, NECOE, Connecticut AG, and the Delaware Commission.

could result in adopting a cost of equity well in excess of the DCF range of reasonableness.

129. Because of concerns about the criteria to be used in evaluating proposals for hypothetical capital structures, many parties, including CREPC, California Commission, NRECA and California Oversight Board, recommend evaluating the proposal on a case-by-case basis, with California Oversight Board arguing for standard of proof much higher than merely having to support the proposal as the NOPR proposes.

130. NECOE states that the Commission should categorically prohibit vertically-integrated utilities from using a hypothetical capital structure. MISO States argues that this incentive is not reasonable, especially if applied to a company's entire rate base, instead of just its new transmission. APPA states that if a specific transmission project is financed separately from other projects within a transmission network (e.g., merchant transmission line), it may be appropriate to evaluate its capitalization separately from other affiliates; however, the evaluation should be based on actual capitalization instead of hypothetical capitalization. In contrast, Ameren asserts that hypothetical capital structures beyond project-financed investments can be supported and should be considered on a case-by-case basis.[87]

[87] Ameren states that the Commission has approved the use of a hypothetical capital structure to better reflect the risk profile of a regulated enterprise. See High Island Offshore Systems, L.L.C., 110 FERC ¶ 61,043, at P 143, order on reh'g, 112 FERC ¶ 61,050 (2005) (High Island).

c. Commission Determination

131. The Commission finds that hypothetical capital structures can be an effective tool available to public utilities to foster transmission investment in appropriate circumstances. As some commenters point out, use of a hypothetical capital structure is not new. For example, the Commission has allowed independent transmission companies to use a hypothetical capital structure to recognize the significant benefits of independent ownership and operation of transmission including, among other things, improved access to capital markets for transmission investment[88] and the Commission has allowed its use for specific projects when shown to be necessary for project financing, among other things.[89] Further, as PJM argues in its comments, hypothetical capital structures may be effective for development of consortium projects. This can be especially important for projects with a diverse set of sponsors, some of which have different capital structures, (e.g., a power marketing agency that contributes access but no equity compared to a project sponsor that brings only equity to a proposed investment). We note the rise in interest in these types of projects, including such large-scale, multiple-developer projects as the Frontier Line and TransWest proposals. Thus, the Commission finds that, in certain contexts, this incentive is appropriate for consideration under section 219 because it has

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[88] METC, 105 FERC ¶ 61,214 at P 20.

[89] Western, supra note 2.

been demonstrated to foster the development of transmission investment, as indicated by the experience of American Transmission and Trans-Elect.

132. The Commission continues to believe that an overly rigid approach to evaluating proposed capital structures may discourage the development of new transmission projects. Therefore, the Commission will evaluate each proposal on a case-by-case basis but will not prescribe specific criteria or set target debt/equity ratios for evaluating hypothetical capital structures, as requested by some commenters.[90]

133. We will not categorically deny the incentive to vertically-integrated utilities, as recommended by NECOE. We agree with Ameren that there may be circumstances in which a hypothetical capital structure may be appropriate for a transmission investment by a vertically-integrated utility. However, we are not suggesting that hypothetical capital structures will become the norm. As with the other incentives, we will require that the applicant demonstrate a nexus between its proposed incentive and the facts of its particular case.

134. In this regard, we note that many of the instances in which hypothetical capital structures are used and can be used reflect unique circumstances, such as a project or consortium that requires a special capital structure where the capital structure may change significantly with new investments. We disagree with TDU Systems that the

[90] We note that many commenters support case-by-case review and recognize the merits of evaluating the specific circumstances of hypothetical capital structure proposals.

Commission has (or should adopt) a general policy on when to use hypothetical capital structures. Moreover, we do not believe that the Commission's recent approvals of hypothetical capital structures for electric transmission companies have resulted in abnormally high equity ratios or over-compensation for the equity holder at the expense of the ratepayer.

4. Accelerated Depreciation

a. Background

135. In the NOPR (at P 30), the Commission proposed accelerated depreciation as another way to increase cash flow to utilities, thereby removing a potential disincentive to investing. The Commission has determined that in some circumstances allowing accelerated depreciation is warranted to encourage investment in transmission infrastructure because it provides improved cash flow and better positions public utilities for longer-term transmission investments.[91] The Commission stated that permitting accelerated depreciation more broadly than just for emergency conditions or special projects may further the goals of section 219 by providing incentives to undertake transmission projects that have the potential to reduce the cost of delivered power and ensure reliability, and, therefore, proposed to allow transmission facilities to be

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[91] See Removing Obstacles and Western, supra note 2.

depreciated over a period of 15 years, in place of the typical Commission practice to allow depreciation over the useful life of the facilities.[92]

136. The Commission also sought comment on two issues. The Commission asked whether 15 years is an appropriate time period for cost recovery or whether the Commission should establish a presumption of a shorter or longer depreciable life for new transmission facilities.[93] The Commission also requested comment on whether accelerated depreciation has any longer-term negative impacts that would undermine the goals of section 219.

b. Comments

137. A number of commenters support the proposal to allow accelerated depreciation of 15 years for the reasons set forth in the NOPR.[94] Some of the supporters, such as the Delaware Commission, KCPL, International Transmission, NYSEG and RGE, Progress, Siemens, Upper Great Plains, and United Illuminating recommend that the incentive should be optional.

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[92] Removing Obstacles, 94 FERC ¶ 61,272, at 61,968-69.

[93] For example, in Removing Obstacles, the Commission permitted a 10-year depreciable life for facilities that will increase transmission capacity to relieve existing constraints and could be in service within a few months.

[94] E.g., Ameren, EEI, BG&E, FirstEnergy, NSTAR, PG&E, PJM, PJM TOs, SCE and WPS. Ameren, MidAmerican and Nevada Companies assert that the Commission should be receptive to a shorter depreciable life or that a different life may be appropriate, possibly tied to the term of a service agreement.

138. Other commenters oppose the proposal to allow accelerated depreciation of transmission facilities.[95] For example, Connecticut AG, NECOE and TANC assert the accelerated depreciation incentive will increase costs and rates and result in gold-plating and over-building of transmission infrastructure. APPA claims that after new transmission facilities have been depreciated over the shorter time period proposed by the Commission, the transmission owners will essentially be providing transmission service for free. APPA is concerned that when this happens the transmission owners will propose to "recalibrate" (i.e., increase) the transmission rate base to depreciate the same facilities yet another time at ratepayer expense.

139. Additionally, TAPS opposes accelerated depreciation because transmitting utilities will no longer earn a return on their investments after the facility has been depreciated and would potentially seek to recover a management fee which would deny ratepayers of the supposed benefits of accelerated depreciation.[96] TAPS claims that given the likelihood of this management fee, the Commission cannot refer to accelerated depreciation as a timing difference. Ameren, on the other hand, states the one drawback to accelerated depreciation is that once the asset has been fully depreciated, the public

[95] E.g., TDU Systems, the California Commission, APPA, the Connecticut AG, NY Association, NECOE, TAPS, the New York Commission and TANC.

[96] TAPS cites High Island, 110 FERC ¶ 61,043, at P 105-115.

utility can not earn a return.[97] Ameren states the Commission should consider generic procedures for the establishment of compensatory management fees for fully depreciated transmission assets.

140. TAPS also argues that accelerated depreciation would skew investments towards depreciable plant and away from non-depreciable land even if acquisition of rights-of-way was the cheaper alternative. TAPS states that, if the Commission is intent on permitting accelerated depreciation, the Commission should require the utility to auction off the fully depreciated facilities at full market value with the proceeds credited to ratepayers.

141. California Commission opposes accelerated depreciation because when a facility is placed into service, the value of the undepreciated plant is at its highest; therefore, the company earns a high return on the plant. As a result, the company has immediate cash flow that does not need to be enhanced. California Commission, TAPS and TDU Systems express concern that accelerated depreciation may cause generational inequities between those who pay for the facilities now and those who do not have to pay later.

142. EEI states that this incentive should not be dependent on corporate structure, should not be limited to 15 years when it may be appropriate to use a shorter depreciable life for certain facilities, and when 15 years is used by a public utility, the company should be able to match the tax law depreciation methodology, which weights the tax

[97] AEP and International Transmission also note this concern.

depreciation more heavily toward the beginning of the life of the project rather than spreading it evenly over 15 years.

143. APPA cites to a number of concerns including the effect of such accelerated depreciation on book-tax timing differences, and the associated deferred tax accounts, and complications in calculating inter-period income tax allocations. APPA also contends that, if the Commission allows rate recovery over a 15 year life for transmission assets, then there should be no provision for deferred income taxes allowed with respect to such assets in any rate case (and no deduction from rate base), because such book and taxable income with respect to such assets would then be matched.

144. International Transmission asserts that in Order No. 618, the Commission correctly determined that the choice of depreciation method should be left to industry.[98] International Transmission argues that flexibility in determining depreciation methods is particularly important when new technologies are deployed that may not be proven, may cost more or have uncertain useful lives, and may be needed to accommodate ongoing industry restructuring or regulatory innovation.

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[98] Depreciation Accounting, Order No. 618, FERC Stats. and Regs. ¶ 31,104, at 31,694 (2000)(Order No. 618). According to International Transmission, in Order No. 618, the Commission modified its initial proposal to require straight-line depreciation to permit other methods of depreciation that allocated the cost of utility property over its useful life in a systematic and rational manner. The Commission recognized that this approach would "[allow] flexibility in a changing business environment."

145. International Transmission states that accelerated depreciation does not increase cash flow for companies with formula rates as it would for companies with stated rates, because the formula rates reset every year. International Transmission urges the Commission to clarify that any changes to depreciation rates for a company using a formula rate will be accepted as a ministerial filing with issues limited only to estimation of the depreciation life and salvage parameters; and that an added bonus of this approach would permit companies with formula rates to remove from their formula rates, in ministerial filings, accumulated deferred income tax balances from rate base. International Transmission argues that to do so would increase cash coverage ratios and the return on equity during the early years of an asset's life and thereby create a tax-related incentive that furthers the Congressional intent to encourage transmission investment.[99] International Transmission states that if it allows companies to use accelerated depreciation, the Commission will need to revisit its Accounting Directive in Order No. 618, in which the Commission stated that recovery over the useful life generally best matches benefits with costs. International Transmission offer that accelerated depreciation could lead to the following problems: 1) depreciation would no longer be representative of the useful life of assets, 2) the representation of net fixed asset value in financial statements could be distorted; 3) there would be a divergence between

[99] International Transmission notes that Congress reduced the tax depreciable life on transmission investments from 20 years to 15 years to encourage transmission investment. EPAct 2005, section 1308.

Generally Accepted Accounting Principles and Commission reporting and 4) efforts by FASB, the Commission and others to clarify financial reporting could be frustrated.

c. Commission Determination

146. After considering all comments, we will adopt the NOPR proposal to allow, as an option, accelerated depreciation for new transmission facilities that meet the goals of section 219. Accelerated depreciation increases the cash flow of public utilities thereby providing an incentive to undertake transmission investment. However, we are not proposing to grant accelerated depreciation on a generic basis; rather, as with the other incentives, the applicant must demonstrate a nexus between its proposal and the facts of its particular case (e.g., the need for additional cash flow produced by accelerated depreciation in order to fund new transmission investment).

147. We do not share the commenters' concerns that this incentive will result in intergenerational inequity. Most transmission customers are dependent upon the transmission system serving them and are likely to continue to receive transmission service over the long-term. Thus, unlike in power supply situations where there are greater options to change suppliers, there is little likelihood of intergenerational impact through the use of accelerated depreciation for transmission investment. In the event accelerated depreciation results in higher rates in the near-term, most of the same customers paying the higher rates will benefit from lower transmission rates in the longer-term. We clarify that the use of accelerated depreciation may be proposed for new transmission facilities including additions to capacity on existing facilities.

148. Given the long-term under-investment in transmission, we disagree with the comments of the California Commission that existing policy is sufficient to encourage transmission investment in all situations. As the California Commission is aware, Trans-Elect stated that accelerated depreciation was a necessary component for its participation in the Path 15 project. In response to the mandate of section 219, we believe it is appropriate to offer this rate treatment more broadly to encourage the same successful outcome that was achieved with Path 15. This does not mean that accelerated depreciation is necessary or will be granted for every project. Instead, the applicant will be required to demonstrate that there is a need for the additional cash flow produced by the accelerated depreciation or that the incentive is appropriate for other reasons. Likewise, at this juncture, concerns expressed by some commenters about the potential for overbuilding of transmission facilities as a result of this rate treatment are unsupported and highly speculative.

149. We concur with the comments that suggest the need for flexibility in the length of the depreciable life. Therefore, public utilities may propose using accelerated depreciation for rate purposes over a period of time as short as 15 years. Moreover, we will consider, on a case-by-case basis, depreciable lives of less than 15 years because shorter depreciable lives may be appropriate in certain cases, such as advanced technologies for which the useful life is not necessarily known.

150. Based on the comments, we are mindful of the potential consequences of this rate treatment when the facilities are fully depreciated. Commenters express concern that the

Commission will allow public utilities to recalibrate the amount of depreciation, or institute a management fee. Other commenters state the Commission should require certain rules for sale of the facilities because of complications that will arise from selling fully depreciated assets. We will not address those issues here but will address such issues if and when they occur.

151. Commenters raise various accounting issues. With respect to the effect of this rate treatment on ADIT (accumulated deferred incomes taxes), we disagree that this proposal will necessarily require that no provision for deferred incomes taxes be allowed with respect to such assets (and no deduction from rate base). As stated previously, we are going to be flexible with respect to the depreciable lives of qualifying assets; therefore, public utilities may choose 30 years as Trans-Elect did with Path 15 and as a result deferred income taxes may still be necessary. Moreover, even if public utilities choose 15 years, depreciation expense for rate recovery purposes will likely be calculated using the straight-line method over those 15 years,[100] while accelerated depreciation for tax purposes may be calculated using a different method (e.g., double declining balance) over 15 years. Therefore, despite the use of the same 15 year life, method differences could continue to create timing differences for which deferred income taxes would be required.

[100] The straight-line method is typically used by utilities and will likely continue to be used for most utility property. However, consistent with Order No. 618 we will not require its universal use, as that may be overly prescriptive. Order No. 618 at 31,694.

152. With respect to APPA's concern about potential difficulties in applying SFAS 71,[101] the Commission and other rate regulatory authorities often include amounts in allowable costs for ratemaking purposes in periods other than the period in which those amounts would ordinarily be charged to expense or included in income for financial accounting purposes. In those instances, the rate actions of regulators have economic consequences that must be recognized in financial statements. Under both SFAS 71 and the Commission's Uniform System of Accounts, if regulation provides reasonable assurance that incurred costs will be recovered in future periods, companies must capitalize the costs. If current recovery is provided for costs that are expected to be incurred in the future, companies must recognize the current receipts as a credit amount on the balance sheet. Therefore, because the accounting requirements for accelerated depreciation are no different than accounting for the economic consequences of other rate actions, we do not see an impediment to implementing accelerated rate recovery of transmission assets.

153. We are not persuaded that we need to revisit Order No. 618 in this proceeding as some commenters suggest. In Order No. 618, the Commission established standards for determining depreciation expense for book purposes. Here we are establishing a standard

[101] SFAS 71 applies to general-purpose external financial statements of an enterprise that has regulated operations. The Commission's Uniform System of Accounts for Public Utilities and Licensees (18 C.F.R. Part 101) contains provisions similar to SFAS 71 that apply to financial statements public utilities must file with the Commission.

for determining depreciation expense allowable for rate purposes. Although accounting and cost-based rate setting generally share common standards, there are instances, and this is one, where different standards should be used by each discipline and the difference bridged by recognition of regulatory assets or liabilities as provided for in our Uniform System of Accounts.[102] Therefore, companies will continue to depreciate transmission assets over their economic service life in a systematic and rational manner for accounting purposes and separately recognize as a regulatory liability any difference between depreciation expense recognized for accounting purposes and accelerated depreciation expense included in the development of rates. In order to clarify this distinction the Commission shall revise § 35.35(d)(1)(v) of the regulatory text proposed in the NOPR which read "(v) accelerated regulatory book depreciation." The revised regulatory text shall read "(v) accelerated depreciation used for rate recovery."

154. We deny International Transmission's request to alter our section 205 filing requirements for public utilities operating under formula rates. In Order No. 618, the Commission permitted utilities to not make a filing to change depreciation rates for accounting purposes but maintained the filing requirement for changes in depreciation rates for rate purposes.[103] The Commission said it would monitor changes in depreciation rates for accounting purposes when companies filed for rate changes. We decline in this

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[102] 18 CFR Part 101.

[103] Order No. 618 at 31,695.

Final Rule to adopt International Transmission's requested changes to formula rates. International Transmission is free to petition the Commission to revise its formula rate to allow flexibility going forward, but we decline to make such a generic determination here because to do so would presume that all formula rates worked in the same manner.

5. Recovery of Costs of Abandoned Facilities

a. Background

155. The Commission noted that public utilities, in considering investments that fulfill the requirements of FPA section 219, may encounter investment opportunities with significant risk associated with factors beyond their control, such as generation developers' decisions to develop or terminate the development of potential resources or difficulty obtaining state or local siting approvals. In these circumstances, the Commission stated that it may be appropriate to consider ways to reduce the risk associated with potential upgrades or other improvements to the transmission system. To reduce the uncertainty associated with higher risk projects, thereby facilitating investment in these projects, the Commission proposed allowing recovery of 100 percent of the prudently incurred costs of transmission facilities that are cancelled or abandoned due to factors beyond the control of the public utility.

156. The Commission's proposal was an extension of a recent Commission decision to allow Southern California Edison Company[104] to recover all prudently incurred costs related to certain proposed transmission facilities if those facilities were later cancelled or abandoned.[105] The Commission noted that the company's management did not control the decision to develop or cancel the wind farm generation project and that the company's shareholders did not share in the earnings associated with the generation project. The Commission further determined that the company might be at a higher risk in developing the project because of factors beyond its control. It also noted that SCE was not a wind farm developer and therefore would not directly benefit from the facilities. Thus, the Commission concluded that SCE should not shoulder the risk of the project.[106]

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[104] SCE, 112 FERC ¶ 61,014 at P 58-61, reh'g denied, 113 FERC ¶ 61,143 at P 9-15.

[105] Prior to SCE, the Commission's policy with respect to recovery of cancelled plant costs provided that 50 percent of the prudently incurred costs of a cancelled generating plant should be amortized as an expense over a period reflecting the life of the plant if it had been completed and that the remaining 50 percent of the prudently incurred costs of the cancelled plant should be written off as a loss. Under this policy, ratepayers are entitled to the income tax deduction associated with that portion of the loss for which they are paying. In addition, they are entitled to a rate base reduction to reflect the accumulated deferred income tax amounts associated with 50 percent of the abandonment loss. See New England Power Co., Opinion No. 295, 42 FERC ¶ 61,016 at 61,068, 61,081-83, order on reh'g, 43 FERC ¶ 61,285 (1988). See also, Public Service Company of New Mexico, 75 FERC ¶ 61,266 at 61,859 (1996) (PSNew Mexico).

[106] SCE. at P 61.

b. Comments

157. A number of commenters support the 100 percent recovery of prudently incurred costs of transmission projects that must be abandoned for reasons beyond the transmission provider's control as a way to reduce the up-front risk associated with important regional projects.[107] Some, like the Kentucky Commission,[108] advocate that the Commission should adopt a case-by-case approach to recovery of costs related to cancelled plant.[109] Kentucky Commission agrees that this incentive should be evaluated on a case-by-case basis to ensure that the decision to abandon the facility was truly beyond the utility's control. California Commission and CADWR do not oppose the recovery of 100 percent of the recovery of prudently incurred costs as long as the determination is made on a case-by-case basis. International Transmission states that preliminary surveys and investigations should also be included in the costs that can be recovered.

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[107] E.g., AWEA, Ameren, AEP, EEI, KCPL, NSTAR, Vectren, International Transmission, WPS, APPA, NYSEG-RGE, NorthWestern, National Grid, New York Commission, NY Association, Progress, PNM and TNMP, SDG&E, and Upper Great Plains.

[108] E.g., California Commission and CADWR.

[109] Trans-Elect supports the case-by-case approach and cites San Diego Gas & Elec. Co., 98 FERC ¶ 61,332 at 62,408, reh'g denied, 100 FERC ¶ 61,073 (2002) ("claims for full recovery of any infrastructure projects that are ultimately cancelled will be addressed by the Commission on a case-specific basis").

158. SCE supports the recovery of abandoned plant and recommends specific standards to facilitate the recovery. SCE states that 100 percent of prudently incurred costs should be approved for recovery if the facility was initially proposed and sited through a process involving stakeholder input and the subsequent decision to abandon is not under the control of management. Additionally, SCE states that utilities should be able to recover the costs of abandoned plant even when they have some control over the decision to abandon but the project was cancelled or abandoned due to problems in obtaining regulatory or other approvals. SCE also supports recovery where economic circumstances have changed, causing there to be no demonstrable net benefits.

159. Others[110] oppose the incentive. For example, CREPC states that guaranteeing the cost recovery of cancelled plant allows investors to ignore risk and places the risk on parties who are unable to manage the risk. ESAI argues that allowing recovery of 100% of prudently incurred development costs runs the risk of producing a proliferation of white elephants.

160. TANC argues that the Commission has upheld and enforced its existing cancelled plant policy and rejected the utility's arguments that it be allowed full recovery of the cancelled plant because it could not get state regulatory approvals; and that the Commission should not adopt a separate policy now.[111] TANC argues the proposal

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[110] E.g., CREPC, the New Mexico AG, Steel Manufacturers and TANC.

[111] TANC cites PSNew Mexico.

violates the intent of Opinion 295-A which is to encourage investors to make efficient production and consumption decisions.

161. Commenters[112] offer numerous instances where they believe it would be inappropriate to allow a utility to recover abandoned plant costs. For example, the Commission should not permit recovery: where the nature of the project was speculative; and where the project was abandoned for reasons within the control of the utility; or where there is an unexpected turn in the economy. TAPS questions whether project abandonment is really beyond a utility's control if a state siting authority does not outright reject a proposal but instead conditions its acceptance in a way that the utility finds objectionable.

162. Snohomish asserts applicants must make showings of why the project failed and recoverable costs should be limited to the original budget. New Mexico AG, TDU Systems and TAPS assert that if utilities are guaranteed their investment in abandoned facilities they need a lower ROE to represent the reduced risk of recovery.

c. Commission Determination

163. We find that an applicant may request 100 percent of prudently-incurred costs associated with abandoned transmission projects can be included in transmission rates if such abandonment is outside the control of management. This incentive will be an

[112] E.g., Industrial Consumers, Oklahoma Commission, PPC, MISO States, and TAPS.

effective means to encourage transmission development by reducing the risk of non-recovery of costs.

164. Many commenters request that we evaluate proposals on a case-by-case basis and we affirm that we intend to do so. The case-by-case approach and the limitation to prudently-incurred costs should adequately discipline investment decisions. However, we will not prescribe specific rules to govern our evaluation but offer limited guidance below.

165. We agree with many commenters that when local, state and federal (as applicable) siting authorities reject an application outright, we would view those circumstances, generally, as abandonment beyond the control of management. As TAPS points out, the situation is less clear when siting authorities do not reject the application outright but add conditions to the application that make it uneconomical or otherwise objectionable. In these instances we would expect the utility to file with the Commission and support the decision to abandon. The Commission will evaluate, in these instances, the change in circumstances from those originally planned on a case-by-case basis.

166. We see no need to specify unique application procedures for this incentive. We will require a section 205 filing for recovery of abandoned plant costs in rates at the time the project is abandoned. We disagree with CREPC that this incentive shifts risk from those who can manage the risk to those who cannot because this incentive is limited by definition to abandonment that is beyond the control of the utility. We will not by rule limit the recovery of costs associated with abandoned plant to the costs included in the

original budget estimate. The Commission will evaluate the public utility's cost recovery to ensure no double recovery of costs. For example, if a utility already recovered survey costs by expensing these costs as a pre-commercial cost, it would be unjust and unreasonable for the utility to recover those costs again if the facility was subsequently abandoned.[113]

167. We will not mandate a reduction in ROE for utilities that receive approval for this rate treatment. As stated in the ROE incentive discussion, determinations of a just and reasonable ROE include risk evaluations made in individual rate proceedings and are based on the facts pertinent to the utility and its proxy group. We note, however, that a utility that receives approval to recover abandoned plant in rate base would likely face lower risk and thus may warrant a lower ROE than would otherwise be the case without this assurance.[114] This does not mean that the Commission would reject an incentive-based ROE for a project that also receives assurance of abandoned plant costs that are beyond the utility's control. We would consider any such request on a case-by-case basis. The risk of a failed project is only one criteria that would be evaluated in determining whether an incentive-based ROE would be appropriate in a given case.

[113] We also clarify that we maintain the timing of recovery as set forth in Opinion No. 295 which required recovery over the life of the asset as if it had gone into service.

[114] SCE, <u>supra</u> note 104.

6. Deferred Cost Recovery

a. Background

168. In the NOPR, the Commission stated that public utilities with a retail rate moratorium may have less incentive to build transmission facilities that could reduce congestion or ensure reliability because of concerns about cost recovery for those facilities. Accordingly, the NOPR proposed to permit such utilities to use a deferred cost recovery mechanism which allows them to commence recovery of new facility costs in FERC-jurisdictional rates at the end of a retail rate moratorium. By providing a mechanism to facilitate cost recovery by public utilities that build transmission facilities during a retail rate moratorium, the Commission believed that it would meet the goals of section 219 by providing certainty to investors that costs can be recovered as quickly as possible.[115]

b. Comments

169. Many commenters support the deferred recovery proposal.[116] International Transmission states that deferred cost recovery should be used to facilitate the divestiture of transmission assets to Transcos. Of those that support the proposal, several urge

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[115] The Commission has approved a deferred cost recovery provision that allowed for the recovery of the cost of new facilities upon the end of a retail rate moratorium. See Trans Elect, Inc., 98 FERC ¶ 61,142, reh'g denied, 98 FERC ¶ 61,368 (2002).

[116] In addition to commenters mentioned below, AEP, Ameren, KCPL, National Grid, Nevada Companies, NSTAR, NYSEG and RGE, and Upper Great Plains also support the proposal.

cooperation between federal and state regulatory authorities.[117] In particular, NSTAR and AEP urge the FERC to collaborate with states and regional state committees to develop solutions for full and timely cost recovery and/or be prepared to intervene in state and court proceedings to the extent state regulators attempt to trap wholesale costs and prevent recovery of those costs in retail rates. EEI urges the Commission to ensure that the necessary regulatory mechanisms are in place to allow cost recovery and should cooperate with the states to develop these recovery mechanisms including transmission cost recovery tracker mechanisms.[118] In EEI's supplemental comments, EEI states that any utility that constructs new transmission facilities should automatically be entitled to deferred cost recovery.

170. Trans-Elect argues that the Commission should allow recovery of all costs approved for deferred recovery for Michigan Electric Transmission Company (METC)[119] and International Transmission.[120]

171. TAPS agrees that deferred cost recovery is reasonable in the case cited in the NOPR in which all connected retail customers pay the same rates and see the same deferral. However, TAPS asserts that allowing utilities with stated rates based on old test

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[117] E.g., PJM TOs, NSTAR, EEI, and AEP.

[118] NU and PEPCO support EEI's comments.

[119] See Michigan Electric Transmission Company, 107 FERC ¶ 61,206 at P12 (2004).

[120] See ITC Holdings, 102 FERC ¶ 61,182 at P 74.

years to defer the collection of additional revenues associated with costs related to new facilities would constitute an unreasonable double-dip and would be inconsistent with section 219(d). Moreover, because the rates of bundled retail customers are set elsewhere based on different test years, this double-dip would be paid only by wholesale customers and unbundled retail customers and would be unreasonable and unduly discriminatory.

172. Several commenters opposing deferred cost recovery cite to concerns about the effect on state regulation.[121] Some argue that the proposal may undermine or impinge on areas exclusively under state jurisdiction (Pennsylvania Commission cites 16 U.S.C. 824 (a)(b)). Others allege that the unrestricted ability of a public utility to defer cost recovery until the end of the rate moratorium may not be consistent with the spirit of settlements struck as part of rate freezes.[122] Pennsylvania Commission adds that all the rate caps in its state are time-limited and any incremental benefit from a federal incentive would be more than offset by the legal uncertainty that would be attached to such incentives and the eventual federal/state conflict that would ensue.

173. MISO States argues that the Commission would do better to work with state authorities on retail rate recovery issues (e.g., ensure rate recovery at wholesale and

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[121] E.g., Kentucky Commission, MISO States, Pennsylvania Commission, and Wyoming Advocate.

[122] Similarly, New Mexico AG, California Commission, PPC and Steel Manufacturers oppose the deferred cost recovery proposal because of the potential effect on state regulation.

retail) than to adopt a policy unilaterally.[123] MISO States comments that Commission statements and accusations that state-statutory retail rate reviews undermine incentive ratemaking at the federal level are unwarranted. If the Commission proceeds with its proposed incentive of allowing deferred cost recovery, the Commission should consider granting deference to objections from state-level officials, according to MISO States.

174. Other commenters[124] seek assurance that the Commission will ensure the company does not over-recover its actual costs; offer that the Commission should adopt a case-by-case approach to allowing deferred cost recovery until the end of a moratorium and requiring agreement by wholesale and retail customers as to the nature, amount and duration over which the costs are to be deferred and synchronization of wholesale and retail ratemaking practices to avoid regulatory price squeeze;[125] and, argue that the Commission should place limits on the amount that can be deferred, and initial deferral period and subsequent recovery period.

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[123] Steel Manufacturers contends that the Commission should instead work cooperatively with states on transmission planning matters, particularly in regional forums, in order to reduce possible areas for dispute, cost recovery gaps, or duplicative cost recovery.

[124] E.g., Municipal Commenters, and APPA.

[125] APPA notes that new transmission facility costs that would be eligible for inclusion as CWIP in rate base should similarly be eligible for deferred cost recovery to address mismatches in cost recovery created by retail rate freezes.

c. Commission Determination

175. We find that permitting public utilities under retail rate freezes to defer recovery of new transmission investment costs undertaken consistent with section 219 will help facilitate investment. Increased certainty of cost recovery of new transmission investment will encourage development of more transmission infrastructure thereby fulfilling the goals of section 219 of the FPA.

176. To date, the Commission has approved deferred cost recovery mechanisms during the formation of Transcos which permitted the new Transcos to defer recovery of other costs such as the ADIT adjustment associated with the acquisition of the transmission system and to defer recovery of the rate differential between the frozen rates and the rate it would have received. As discussed more fully below, we believe that Transcos offer significant benefits and the deferred cost recovery mechanisms that we approved for METC and International Transmission were helpful to establish those Transcos. We also believe that deferred cost recovery mechanisms should be available to all public utilities, not just Transcos and recognize the importance of ensuring that federal and state ratemaking policies align so that we not only reduce regulatory lag but facilitate transmission development.

177. Most of the comments opposing this proposal cite potential conflicts with state regulation to be a critical issue. We believe that deferred cost recovery mechanisms generally will not hinder retail ratemaking. However, if a situation arises where a state regulator believes that a federal deferred cost mechanism conflicts with a state goal or

undermines a state settlement with the applicant, we will consider objections by state regulators on a case-by-case basis, and seek to avoid inconsistencies between state and federal regulation. In this regard, we note that the approval by the Commission of regional state committees provides one vehicle for discussing Federal and state ratemaking issues on a cooperative and regional basis. With respect to TAPS' concern that the cost of the incentive would be recovered from only wholesale customers and unbundled retail customers, the Commission may approve a rate design such that wholesale customers and unbundled retail customers pick up only a proportionate share of the costs of the incentive.

178. With respect to commenters' specific proposals for trackers, limits, and deferral periods, we decline to adopt such proposals here. The justness and reasonableness of any deferred cost recovery proposal will be considered as part of the section 205 filing and there is no basis to arbitrarily place limits on recovery through this rule. The intent of the deferred recovery mechanism is to increase the certainty of cost recovery to encourage more transmission investment. It may also facilitate the creation of Transcos in states where retail rate freezes are in place. The deferred recovery mechanism is an option available for any public utility to propose; a public utility may also propose the use of a regulatory asset, as suggested by APPA.[126] We believe that a public utility must propose

[126] Regardless of whether it proposes to use a regulatory asset, the public utility should explain its proposed accounting for the deferred recovery mechanism.

a set of incentives that is tailored to the facts of its particular case and the Commission must review those proposals to ensure they are just and reasonable.

7. Other Incentives - Single-Issue Ratemaking

a. Background

179. In the NOPR (at 54), the Commission recognized that transmission pricing issues are some of the most difficult issues facing the industry and that the Commission's policy of not allowing selective adjustments to a cost-of-service may serve as a disincentive to transmission investment.[127] Certain applicants may consider the time requirements and the uncertainties associated with rate proceedings that encompass their entire transmission systems to be disincentives to making incentive filings, as specified in the NOPR. To ensure that the approval process for incentive treatment is as streamlined as possible, thereby ensuring timely infrastructure investments, the Commission stated it was willing to consider incentive filings, applicable to both Transcos and traditional public utilities, that propose rates applicable only to the new transmission project.[128]

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[127] See, e.g., City of Westerville, Ohio v. Columbus Southern Power Co., 111 FERC ¶ 61,307 at P 18 & n.11 (2005).

[128] The NOPR cited Removing Obstacles as an example of one type of approach utilizing a limited section 205 filing.

b. Comments

180. Numerous commenters[129] support single issue ratemaking for the reasons set forth in the NOPR. Additionally, Ameren states that single-issue ratemaking can be useful in obtaining advance approvals of specific rate treatments that may be required by investors as a condition to financing new construction.[130] Moreover, Kentucky Commission states that as long as single issue rate cases relate only to new transmission and comply with the filing requirements set forth elsewhere in the NOPR, it does not object to this proposal.

181. FirstEnergy states this proceeding is analogous to the Removing Obstacles orders where, in order to facilitate development of transmission investment the Commission permitted limited section 205 rate applications. FirstEnergy states that in this proceeding, Congress has realized there is a pressing need for transmission investment and the Commission should permit limited section 205 rate applications to facilitate the needed development. FirstEnergy asserts single issue ratemaking is particularly important for companies using formula rates.

182. AEP states that the Commission should be flexible with ratemaking conventions and that single-issue ratemaking could be a powerful incentive to encourage more transmission investment. AEP also states that single-issue ratemaking along with

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[129] E.g., Ameren, EEI, PJM, Trans-Elect, FirstEnergy, NorthWestern, MidAmerican, Nevada Companies, AEP, KCP&L, Semantic and Xcel.

[130] See, e.g., Western, supra note 2 (issuing advance approvals of certain rate treatments for proposed California transmission Path 15 upgrades).

transmission cost trackers at the state level would be productive measures especially with integrated utilities.

183. TDU Systems notes that where the Commission has accepted single issue ratemaking, the Commission required the implementation of a mechanism that would harmonize the rate increase from that surcharge with adjustments to rates for existing facilities to reflect the offsetting decreases in depreciation costs associated with those existing facilities. EEI agrees that it is important to establish a crediting mechanism in some cases to harmonize the rate treatment for new and existing transmission facilities.[131] PJM, Progress, TAPS and TDU Systems state that Schedule 12 of the PJM tariff provides an example of how concerns with single issue ratemaking can be addressed to implement a $/KW/month adder to network or point-to-point transmission rates.[132]

184. TAPS proposes an alternative approach in which the Commission could harmonize the existing rates and new facility rates, when the inputs to the existing rate are known (i.e., not hidden in a "black box" settlement), by updating the load divisor and depreciation reserve, and all other rate components would remain the same (other than the new facility charge). Where the existing rate was black box, a load divisor and

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[131] EEI cites Allegheny Power, 111 FERC ¶ 61,308 at P 54; see also Request for Rehearing of the PJM Transmission Owners, Docket No. ER05-513-001, filed on June 30, 2005.

[132] PJM and TAPS also cite Allegheny Power (accepting cost recovery provisions of Schedule 12).

depreciation reserve would have to be imputed for these purposes by assuming that the difference between the filed-for and settled rate represented an adjustment to the rate divisor and depreciation reserve.

185. Additionally, if the Commission proceeds with single issue ratemaking, APPA, TAPS and SCE suggest having the public utility file a full rate case at some point in the future which would roll-in the existing rate and the separate surcharge for the new transmission investment. APPA and TAPS recommend a full rate case after three years while SCE does not state a specific deadline for a full rate case.

186. APPA, NASUCA and TDU Systems oppose single issue ratemaking for transmission service claiming that public utilities are likely earning returns on their existing transmission facilities in excess of previously allowed rates of return (due to load growth, continuing depreciation of existing transmission facilities, and stale rates). They argue that single issue ratemaking fails to determine if the entire transmission rate is just and reasonable. APPA states that to allow a rate increase for a new facility to be added to the transmission rates charged for existing facilities improperly mixes costs from different periods for the same functional class of facilities. In addition, NASUCA and TDU Systems state that single issue ratemaking violates section 205 because one rate determinant may often be accompanied by an associated decrease in other portions of the rate and failure to consider all rate components together can lead to overstatements that

produce unjust and unreasonable rates.[133] Further, NASUCA states that waivers of the general rule for a full blown rate case are found only in limited circumstances, for example where the utility is merely an accounting conduit for rate changes made by another utility from which the first utility purchases services.[134]

187. Municipal Commenters oppose single issue ratemaking because it represents a departure from cost-of-service ratemaking in that it fails to demonstrate any nexus between the awarding of proposed incentives and the owner's overall cost of service, need, financing cost, capital structure or performance.

188. TAPS suggests an alternative approach of having companies file their incentive rate proposals, individually tailored to that utility where appropriate, but generally applicable to that utility's qualifying transmission investments. Subsequent facility-specific filings, as necessary, would merely apply the existing approved plan. With this approach, single issue ratemaking is unnecessary according to TAPS.

189. In the event that the Commission decides to proceed with allowing single issue ratemaking for new transmission investment projects, commenters have suggested

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[133] NASUCA cites Arkansas Power & Light Co. v. Missouri Public Service Commission, 829 F.2d 1444, 1451-52 (8th Cir. 1987) (A state may determine whether the company has experienced savings in other areas which might offset the increased price resulting from the pass-through of the increased wholesale rate).

[134] NASUCA cites Panhandle Eastern Pipe Line. v. FERC, 613 F. 2d 1120, 1127 (D.C. Cir. 1979).

methodologies for implementing single issue ratemaking and ways to mitigate any potential problems with it.

190. EEI explains that public utilities should be permitted to file with the Commission to establish a revenue requirement to recover the costs of constructing a specific new transmission facility pursuant to section 205. Under this approach, the transmission owner determines whether to establish a new ROE or use its current Commission-approved ROE.

c. Commission Determination

191. We believe that single-issue ratemaking can provide a significant incentive for achieving the infrastructure investment goals of section 219 because it can provide assurance that the decision to construct new infrastructure is evaluated on the basis of the risks and returns of that decision, rather than the additional uncertainty associated with re-opening the applicant's entire base rates to review and litigation. We agree with FirstEnergy that there is a pressing need for transmission investment and therefore the Commission should allow for limited section 205 filings as a way to facilitate needed development, as was approved for the Path 15 project. The Commission's approval of limited section 205 procedures in Removing Obstacles showed how useful and appropriate single-issue ratemaking can be for needed investment in existing facilities, as Trans-Elect attests in their comments.

192. We will not require harmonization of rates, roll-in of new and existing rates or reopening of existing rates in this rule, as recommended by some commenters. Nor will

we specify in this rule the rate calculations associated with developing a transmission rate for a particular new facility. Our concern in this rule is to ensure new investments are not impeded because of existing-system rate issues. Accordingly, applicants filing for single-issue ratemaking for a particular project are only required to address cost and rate issues associated with the new investment in the section 205 proceeding to approve rates. However, the applicant will be required to fully develop and support any transmission rate designed to recover the costs of a particular transmission system facility or upgrade – including cost allocation and rate design. The Commission will consider the potential need to combine or reconcile the new rate with any existing transmission rate when an applicant submits a request for incentives. In some instances, the Commission may find that single-issue ratemaking is appropriate without any determination as to when that rate will be harmonized with existing rates; in other cases, the Commission may, if appropriate, adopt certain of the mechanisms suggested by the commenters, such as a requirement to file a full rate case at a date certain in the future. In each instance, the Commission will balance the need for new infrastructure, and the importance of permitting single issue ratemaking in support of that infrastructure, with the concerns over whether a specific mechanism is required to re-open existing rates or whether the traditional complaint processes are sufficient for that purpose.

193. We find the claims of some commenters that public utilities are currently earning excessive returns on their existing rates to be speculative. We have no basis to conclude earned returns are excessive since these commenters have not submitted section 206

filings alleging such excessive returns nor do they provide evidence in their pleadings identifying the companies that are realizing excessive returns.

C. Incentives Available to Transcos

1. Definition of Transco

a. Background

194. The NOPR (at P 37) proposed to define a Transco as a stand-alone transmission company, approved by the Commission, which sells transmission service at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility. The Commission invited comments on this proposed definition of Transcos.

b. Comments

195. AEP and PEPCO support the proposed definition because it allows a Transco to be affiliated with another public utility. AEP states that eligible entities should include integrated utility companies or their affiliates, and PEPCO that the definition of a Transco should allow for ownership by a single affiliate.

196. Other commenters support a definition that includes affiliated Transcos, but only those with passive ownership. Commenters differed on the level and nature of independence requirements, if any, that should apply to affiliated Transcos. PJM TOs, for example, argued only for the same governance requirements otherwise applicable to Transcos. TAPS, on the other hand, advocates more specific definitions of affiliated Transcos that would need to meet all of the standards of the Policy Statement Regarding

Evaluation of Independent Ownership and Operation of Transmission (Policy Statement Regarding Evaluation of Independent Ownership).[135] Several commenters, including APPA and ITC, argue for the benefits of independence. Vectren opposes the proposed definition of Transco in the NOPR because by permitting inclusion of transmission owners with affiliates that own generation and/or distribution, it allows a Transco to be substantially identical to a vertically-integrated utility. Vectren questions whether the Commission's policy initiatives would have more impact on an FPA jurisdictional Transco with generation and distribution affiliates than on a traditional integrated transmission owner due to the Transco's parent company's common equity ownership of transmission and distribution as well as its role in making critical Transco business decisions. Vectren also argues that holding companies with Transcos will utilize shared service companies to fulfill common managerial and administrative functions for Transcos and affiliates.

197. Commenters differed on whether the level of affiliate ownership should bear on the definition of a Transco. For example, Ameren states that utilities exhibiting comparable levels of independence (and benefits) should be entitled to similar rate treatments, regardless of organizational structure. Ameren focuses on the level of functional separation and operational independence of the Transco – and not the

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[135] 111 FERC ¶ 61,473 (2005).

percentage of passive equity ownership. Semantic requests that the Commission define the maximum permitted traditional utility ownership allowed in a Transco.

198. Some commenters, including TransCanada and American Transmission, advocate flexibility regarding ownership in the proposed definition. NSTAR, National Grid, and OMS contend that the Commission's proposed definition of Transco is overly restrictive in applying only to companies that are solely transmission providers. They argue that transmission and distribution companies that have taken significant steps toward independence by divesting of generation and marketing activities be similarly rewarded.

199. Due to concerns about competition for capital within Transcos, TDU Systems states only Transcos with strict limits on investments in other industries should receive incentive rates. APPA states that Transcos must have access to sources of equity capital other than their affiliates, such as through issuance of new equity or through capital contributions from a diverse base of Load Serving Entity owners.

200. Semantic states that the definition of Transco should be broadened to include entities that deliver services using advanced transmission technologies recognized in section 1223(a) of EPAct 2005, such that a Transco need not directly participate in the flow of energy. A Transco could be an "Advanced Technology Transco" that delivers enhanced grid state data processed by analytical software.

c. Commission Determination

201. We will adopt in the Final Rule the definition from the NOPR that a Transco is a stand-alone transmission company that has been approved by the Commission and that

sells transmission services at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility. This definition includes the flexibility advocated by some commenters and allows the Commission to consider various business models and arrangements.

202. The definition we adopt here does not exclude affiliated Transcos with active ownership by market participants, or stand-alone transmission companies that own transmission and distribution facilities. However, we expect applicants to demonstrate the value of their particular affiliated Transco proposal. We will consider the eligibility of such arrangements based on a showing of how the specific characteristics of a proposed Transco affect its ability and propensity to increase transmission investment and lead to increased transmission investment similar to the Transcos we have already approved. We note that the three Transcos established thus far – which have all demonstrated their willingness and ability to invest in new transmission – are either not affiliated with any market participant (e.g., International Transmission and METC) or have joint ownership and board membership by a number of market participants and independent members (e.g., American Transmission). Concerns regarding affiliated Transcos, such as those voiced by Vectren, or support for companies that own transmission and distribution or other business structures, will be considered in the context of specific applications for incentive treatment.

203. In addition, because we do not wish to preclude entities that may help foster investment in needed transmission infrastructure simply because they have not yet been

proposed or evaluated, we will not establish specific limits on Transcos regarding, for example, business investments in other industries, sources of equity, or levels of active and passive ownership.

204. We also clarify that an entity's status as a Transco will not be conditioned on membership in an ISO or RTO. As the Commission explained in the NOPR, just as the need for investment is a national need, we believe that the expansion and investment objectives of new FPA section 219 are best met by a definition of Transcos that does not restrict the formation of Transcos to only certain organized markets. Similarly, we clarify that an applicant that receives an incentive related to its status as a Transco may also request and be eligible for other generally applicable incentives discussed in the Final Rule, such as those for joining an RTO or ISO. The Commission will consider the suitability of multiple incentives at the time of an application.

205. We will not create a new Transco category that includes entities that do not own transmission facilities, as requested by Semantic. Consistent with section 219 the Final Rule applies to rate treatments for transmission of electric energy in interstate commerce by public utilities. To the extent Semantic meets this requirement, it may file an application for incentive treatment and the Commission will then make its determination of whether the Semantic proposal meets the requirements of section 219.

2. Transco ROE Incentive

a. ROE Incentive

i. Background

206. As part of the encouragement of Transco formation, the Commission stated that it will permit suitably structured Transcos to receive an ROE that both encourages Transco formation and is sufficient to attract investment. For example, the Commission approved equity returns for METC and International Transmission that reflect the significant benefits that their status as Transcos provide, and these returns are higher than those approved for integrated entities. Continuing to allow a higher ROE (that falls within a zone of reasonableness) in recognition of the benefits Transcos provide is an appropriate way to ensure the achievement of section 219's objectives. Therefore, the Commission stated that it will consider the positive impact Transcos have on transmission investment and in turn on the reliable or economically efficient transmission and generation of electricity when it evaluates ROEs proposed by properly structured Transcos. (NOPR at P 40, footnote omitted)

ii. Comments

207. Several commenters,[136] oppose the Commission's proposal to grant an ROE

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[136] E.g., APPA, Community Power Alliance, Municipal Commenters, NASUCA, NECPUC, New Mexico AG, NRECA, NU, Pennsylvania Commission, Snohomish, and TANC.

incentive to Transcos outright. Other commenters[137] oppose giving Transcos an incentive that is not available to other business models.

208. Those opposing the outright grant of ROE incentives to Transcos[138] contend, among other things, that: there should be no equity incentive adders without direct demonstration of customer benefits; such incentives would unfairly divert capital to Transcos; and that enhanced Transco ROEs do nothing to solve the problem of building needed transmission.

209. Commenters opposing[139] treatment based on corporate form or business model suggest that the Commission focus on the purpose and effect of the proposed investments, not the type of entity that proposes them. They argue that there is a lack of evidence of how Transcos encourage transmission infrastructure expansion and the track record for Transcos is incomplete.

210. Other commenters raise concerns about the signals the Commission is sending regarding RTOs and independence of operations, planning and expansion that can be ensured through other types of regional transmission groups or through traditional

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[137] E.g., AEP, BG&E, EEI, First Energy, KCPL, MidAmerican and PacifiCorp, Midwest ISO, NECPUC, Northwestern, PEPCO, PJM, PJM TOs, PPC, Progress Energy, SCE, Southern Companies, and Vectren.

[138] E.g., Municipal Commenters, NECPUC, Progress Energy, Snohomish, PPC.

[139] E.g., APPA, Community Power Alliance, FirstEnergy, Pennsylvania Commission and NASUCA.

utilities, particularly those in a RTO with a regional planning process.[140] EEI, for example, opposes the Commission managing business models and argues the Commission should not (even unintentionally) give the impression through incentives that it seeks to restructure the transmission sector.

211. Other commenters offer suggestions as to how to distinguish incentives. For example, NU and PJM suggest targeting incentives at companies that are investing in transmission and/or involved in regional planning, regardless of corporate structure. PJM suggests the Commission proceed on a case-by-case basis.

212. Finally, commenters argue that higher ROEs for only some transmission owners are discriminatory and not just and reasonable, and have no basis in section 219. Alternatively, some suggest that Transcos have lower risk than integrated companies and should receive lower ROEs. Others argue that incentives should cover only new investments and behavior,[141] not existing infrastructure. For example, California Commission opposes providing higher ROEs to Transcos, arguing that Transco and traditional integrated utility shareholders bear the same (and only significant) risk as transmission project owners - during the initial stage of project permitting and developing. SCE offers that Transco-specific ROEs might actually provide a disincentive

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[140] E.g., American Wind, Mid American, PacifiCorp, and EEI.

[141] E.g., New Mexico AG, NRECA, Pennsylvania Commission, PG&E, Vectren, Southern Companies, California Commission, SCE, and TANC.

for future Commission-jurisdictional transmission investments by traditional utilities if they can earn higher ROEs on state-jurisdictional facilities. TANC offers that a for-profit Transco has no incentive to make, and, in fact, is discouraged from making, economically efficient and/or energy efficient investments. Dairyland points out that American Transmission's plans for substantial investment were made in the context of a settlement agreement in which American Transmission agreed to a lower ROE than that approved for Midwest ISO transmission owners and that the settlement improved American Transmission's cash flow and reduced its risk, providing a sufficient financial package to enable its investments even with the lower ROE. Dairyland states that American Transmission shows that substantial investment by Transcos is likely to occur even if ROEs are reduced.

213. Some commenters take issue with the representations in the NOPR regarding state and federal jurisdiction.[142] For example, Community Power Alliance opposes rewarding changes in ownership structure resulting in transfer of jurisdiction from state to federal regulators. PEPCO believes the NOPR suggests that traditional utilities may be treated less well by federal regulators merely because they are subject to state as well as federal jurisdiction. New Mexico AG states Transco incentives are nothing more than an attempt by the Commission to override state regulatory jurisdiction. Nevada Companies state

[142] E.g., Community Power Alliance, PEPCO, NSTAR, and PJM TOs.

that the Commission must work with state regulatory authorities to foster Transco formation.

214. TDU Systems opposes incentive rates for new investment by Transcos after those Transcos form. If any such award is granted, TDU Systems argues it be done only upon demonstration of need, and apply only to system expansions, not existing facilities.

215. Other commenters,[143] generally support incentive-based ROEs to encourage Transco formation. For example, International Transmission supports incentives for Transco formation and investment not merely to reward a particular transmission ownership structure but to encourage a type of transmission ownership that has produced the results that Congress sought when it enacted section 219. International Transmission states that both its own specific experience and the track record of Transcos generally illustrate the benefits of Transco ownership of transmission.[144] International Transmission

[143] E.g., International Transmission, KKR, Nevada Companies, TDU Systems, Trans-Elect and Upper Great Plains.

[144] International Transmission states that in the last decade of Detroit Edison's ownership of the facilities now owned by International Transmission, Detroit Edison invested about $10 million a year in those transmission facilities that International Transmission states it invested $41 million on in 2003; $82 million on in 2004; and over $118 million on in 2005. At the end of 2005, the net asset value of International Transmission's facilities has nearly doubled while its CWIP balance remained roughly flat. International Transmission states that this substantially increased investment is producing benefits for consumers in enhanced reliability and increased access to competitively priced generation. International Transmission states that in the latest Midwest ISO Transmission System Expansion Plan, the three transcos in the Midwest ISO account for 54 percent of the approximately $2.9 billion in projected investment through 2009. Comparing the level of projected investment across transcos and non-

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states that if other forms of transmission ownership invest in transmission in a manner comparable to Transcos, those other entities should be eligible for equal incentives, but that until they do, Transco-specific incentives are fully appropriate.

216. KKR offers the following potential investment advantages of Transcos: elimination of competition for capital between generation and transmission functions; a singular focus on transmission investment which allows more rapid and precise response to market signals indicating when and where transmission investment is needed; a lack of incentive to maintain congestion in order to protect generation market share; and an enhanced ability to manage assets and access to capital markets. As stand-alone entities lacking incentive to favor a particular market participant's generation, Transcos are likely to attract a variety of new generators, including solar and wind renewable generation.

217. KKR states that enhanced ROE can both drive capital investment and support Transco formation. An enhanced ROE in excess of that sufficient to support new investment will be factored into the purchase price of the Transco assets or company and be delivered in whole or in part to the seller.

218. Additional comments in support of higher ROEs for Transcos,[145] note that Transco formation and investment will occur when actual Transco returns are equal to or greater

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transcos, the average transco in the Midwest ISO is investing at over <u>seven times</u> the rate of the average non-transco in the Midwest ISO.

[145] <u>E.g.</u>, Nevada Companies and Trans-Elect.

than returns for investments with comparable risk and that these returns must be earned on a consistent basis.

219. Trans-Elect offers suggestions on the manner in which the incentive could be tied specifically (and exclusively) to the acquired facilities. In addition, Trans-Elect states that whatever methodology is used to develop a range of equity cost estimates, use of the mid-point (or average) of that range would be contrary to the notion of stimulating new transmission investment. Particularly in the context of the inherently higher-risk Transco business model, Trans-Elect supports ROEs toward (or at) the high end of the range.

220. Upper Great Plains supports Transco incentives but argues they be limited to what is necessary to put Transcos on an equal footing with other transmission developers. According to Upper Great Plains, leveling the playing field will encourage Transcos to more fully develop the advantages made possible by their business structure.

iii. Commission Determination

221. After considering all the comments, we adopt in this Final Rule the proposal from the NOPR to provide to Transcos a ROE that both encourages Transco formation and is sufficient to attract investment after the Transco is formed. The incentive ROE does not preclude a Transco from applying for any other incentive adopted in this rule, including hypothetical capital structures, ADIT, acquisition premiums, formula rates or deferred cost recovery. We note that such additional incentives could aid the formation of Transcos as well as bolster their ability to add transmission infrastructure. We note, in addition, that application of the ROE incentive or applicable other incentives will likely

be more efficiently translated into rates for those applicants that operate under or concurrently propose formula rates.

222. This decision is based on the proven and encouraging track record of Transco investment in transmission infrastructure. For example, International Transmission states that its investment was more than ten times higher in 2005 than the annual investment by DTE during the last decade of DTE's ownership of the same transmission system.[146] Trans-Elect states that it expended $112 million in capital on its system from May 2002 through 2005.[147] Since January 1, 2001, American Transmission states that it has invested approximately $1 billion in strengthening its system, essentially tripling its investment in transmission infrastructure in five years.

223. The expansion plans of existing Transcos are also encouraging. International Transmission notes that in the latest Midwest ISO Transmission System Expansion Plan, the three Transcos in the Midwest ISO account for 54 percent of the Plan's approximately $2.9 billion in projected investment through 2009. It also states that comparing the level of projected investment across Transcos and non-Transcos, the average Transco in the Midwest ISO is investing at a rate that is over seven times that of the average non-Transco in the Midwest ISO.[148]

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[146] International Transmission comments at 21.

[147] METC comments at 3.

[148] International Transmission Reply Comments at 6.

224. As stated in the NOPR, the Commission believes that this positive record of Transco investment in transmission facilities is related to the stand-alone nature of these entities.[149] In particular, we agree with the comments submitted by KKR explaining the benefits of the Transco model. By eliminating competition for capital between generation and transmission functions and thereby maintaining a singular focus on transmission investment, the Transco model responds more rapidly and precisely to market signals indicating when and where transmission investment is needed. We agree that Transcos have no incentive to maintain congestion in order to protect their owned generation. Moreover, Transcos' for-profit nature, combined with a transmission-only business model, enhances asset management and access to capital markets and provides greater incentives to develop innovative services. By virtue of their stand-alone nature, Transcos also provide non-discriminatory access to all grid users.

225. Numerous commenters state that the Commission should not favor one corporate structure (i.e., Transcos) over another. We agree in part. In the context of the goal to increase investment in needed transmission infrastructure, it is inappropriate to favor one corporate structure over another to the extent both business structures have similar transmission investment records. To date, however, no other business structure has a transmission investment record similar to that of a Transco and therefore our incentives that focus on Transcos are justified. While this rule provides incentives for all public

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[149] NOPR at P 39.

utilities, the additional incentives for Transcos, in light of their superior record of adding infrastructure, are neither unduly discriminatory nor contrary to the goals of section 219.

226. We believe an incentive ROE for Transcos is justified because Transcos are spending their additional return on capital spending, as demonstrated by the negative cash flow profiles of the current Transcos and their future capital spending plans, as discussed in the comments of the Transcos and KKR. Though Transcos have demonstrated that they will build transmission, and plan to build more in the future, we agree with commenters that state that our focus should be on actual results—i.e., getting transmission built. Currently, Transcos are spending capital aggressively, reinvesting any earned returns and spending a significant amount more than they are earning. However, continuing to allow a Transco, over the long-term, to receive an incentive ROE for all its facilities that recognizes its increased transmission investment only makes sense if the Transco continues to provide the benefits which we are trying to incentive. Therefore, as discussed earlier, we encourage Transco applicants to submit proposals to measure performance and thereby justify continuation of ROEs (as well as other rate treatments) that were provided for the purpose of attracting and sustaining transmission investments.

227. We disagree with AWEA’s statement that single-system Transcos do nothing for regional goals. Even a single-system Transco can build infrastructure that significantly aids a broad region. Moreover, to the extent Transcos belong to transmission organizations, their expansion plans must be approved by transmission organizations and therefore they support regional planning goals.

228. We disagree with Municipal Commenters' contention that the Transco incentive is misguided as transmission prices have increased dramatically in regions where the transmission systems were spun off from investor owned utilities. We have no evidence that Transcos have increased prices, nor did Municipal Commenters provide supporting evidence. Nor do we agree Transco formation would simply increase earnings without any direct demonstration of customer benefits from such formation. The amount of infrastructure likely to be added by Transcos will directly benefit customers in the region. Responding to the Pennsylvania Commission, we have no basis to conclude Transcos may introduce undesirable biases in grid investment and operations. Furthermore, like any public utility, their rates remain subject to review to ensure justness and reasonableness. We therefore have no basis to change our conclusion that Transcos are appropriate structures for investment in infrastructure and accomplishment of the objectives of section 219.

229. In response to concerns of commenters such as NRECA and the California Commission that the incentive return for Transcos is not based on a risk evaluation of Transcos, we believe those concerns are premature. Such an evaluation is more appropriately part of the section 205 process in individual rate applications of assessing representative proxy companies and the impact of other factors, including risk.

230. We expect that providing for deferred cost recovery for Transcos, such as has been approved for Trans-Elect and International Transmission, will address Nevada

Companies' concern that state-level rate freezes could preclude recovery of costs associated with divesting transmission assets to Transcos.

231. We believe PEPCO and the New Mexico AG have misinterpreted our statements in the NOPR regarding benefits of federal jurisdiction for Transcos. The NOPR does not state that a state's jurisdiction over some of the activities and assets of traditional utilities hinders investment, as PEPCO maintains. Rather, the NOPR indicated that Transcos would benefit from having incentive approvals determined in a single jurisdiction, by eliminating delay and uncertainty. The purpose of our policy of incentives for Transcos is to build much needed transmission infrastructure. States continue to have jurisdiction over the siting of new transmission infrastructure and many of the high voltage interstate projects will require extraordinary cooperation and collaboration between state and Federal regulators.

b. Transco Level of Independence

i. Background

232. The Commission proposed to clarify and broaden the definition of Transcos to be stand-alone transmission companies approved by the Commission, without a condition of membership in a RTO or ISO, and requested comment on how to factor the level of independence into any request for ROE-based incentives for Transcos. The Commission sought comment on whether it should specify additional incentive levels within the zone of reasonableness to correspond to certain levels of independence and if so, what those amounts should be. The Commission also sought comments concerning whether

membership in an RTO or ISO should be considered in setting incentive-based ROEs approved by the Commission for a Transco.[150]

ii. Comments

233. Numerous commenters[151] generally support tying the level of incentives to the level of independence of the Transco. For example, Ameren proposes a tiered approach to ROE incentives, with Transcos that are members of an RTO or ISO entitled to the highest ROE incentive. International Transmission states that it is appropriate to award the highest ROE-based incentives to Transcos that are truly independent. KKR states that Transcos that have achieved total structural independence should receive the most generous set of incentives. MISO States state that the level of Transco independence is an important consideration and, accordingly, the Commission could apply a graduated ROE incentive depending upon the degree of independence between the Transco and market participants, affiliates or generation.

234. National Grid states that the Commission should establish the level of ROE-based incentives based on a sliding scale keyed to various levels of independence for all forms of Transmission Organizations, with one end of the sliding scale being "total structural independence," which would be entitled to full incentives.

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[150] NOPR at P 42.

[151] E.g., Ameren, AWEA, Connecticut DPUC, International Transmission, KKR, MISO States, and National Grid.

235. Trans-Elect states that only entities that establish independence as to operation, planning, construction and investment decisions should qualify for ROE-based incentives for Transcos. Rather than recognizing a “range” or “levels” of independence that would justify “additional incentive levels,” the Commission should confirm that entities that meet the definition of Transco would qualify for the full ROE-based incentive, while those that do not would not be eligible for the incentive. According to Trans-Elect, it is critical that Transco ownership arrangements that reflect truly passive ownership qualify for the full ROE-based incentive and that the independence standard should be deemed satisfied when passive ownership is structured to ensure that the Transco will “operate free of market participant control or influence.”

236. TDU Systems supports a policy to prevent a Transco with passive ownership interests from earning Transco incentives. TDU Systems assert that should the Commission authorize passive ownership interests by market participants in Transcos, those relationships should be rigorously scrutinized. Passive ownership interests by market participants in Transcos should only be authorized upon a showing that the option of investment in the Transco is open to all LSEs in the region up to their load ratio shares, according to TDU Systems, with governance based on equal and/or equally-weighted votes, if any, for all passive owners. TDU Systems recommend that the Commission commit to monitor these relationships in order to deter the potential for abuse.

237. Some commenters also address whether membership in an RTO or ISO should be considered in setting incentive-based ROEs approved by the Commission for a Transco.

For example, PEPCO states that the Commission should not provide additional incentive levels for certain levels of Transco "independence" unless it also provides the same incentive levels for participants in other models, such as RTOs. MISO States and PJM believe that the Commission should reverse its proposed policy of not taking into account if the Transco is a member of an RTO and instead recognize the positive benefits of Transco membership in RTOs. AWEA states that incentives for regionalizing the grid through RTO participation should be an additional incentive.

238. Others, such as APPA, NRECA, and PG&E support the Commission's proposal that membership in an RTO or ISO should not be a factor in setting incentive-based ROEs for Transcos. WPS states that the proposed incentive for Transcos may be appropriate, but also could be duplicative if the Transco is an RTO member and also receives an incentive for that membership.

iii. <u>Commission Determination</u>

239. We will not establish a specific methodology to factor the level of independence into any request for ROE-based incentives for Transcos. We will also not specify additional incentive levels that remain within the zone of reasonableness, to correspond to certain levels of independence. While not quantifying a precise formula or method, we will consider the level of independence of a Transco as part of our analysis when we determine the proper ROE for the Transco, and evaluate the specific attributes of a particular proposal, including the level of independence, to determine appropriate incentives.

240. Though we are not establishing a range of incentives based on independence, we note that the three existing Transcos, which have significantly increased their transmission investment post-formation, are either totally independent of market participants or can meet the independence standards in the Policy Statement Regarding Evaluation of Independent Ownership. Independence is an important component of the positive contribution of Transcos on investment in needed transmission infrastructure. A Transco with active ownership by a market participant or other new business arrangements is also eligible for Transco incentives to the extent it can show, for example, why active ownership by an affiliate does not affect the integrity of its investment planning, capital formation, and investment processes or how its business structure provides support for transmission investments in a way similar to the structure of non-affiliated Transcos or Transcos with only passive ownership by market participants.

241. In addition, while a Transco need not be a member of an RTO, ISO, or other Transmission Organization, we will also consider such membership as part of our evaluation process on the level of Transco incentives that might be appropriate. We also note that a Transco is eligible for incentives if it is a member in an RTO, ISO, or other Transmission Organization.

3. <u>Accumulated Deferred Income Taxes (ADIT)</u>

a. <u>Background</u>

242. To remove any disincentives that might prevent the sale or purchase of

transmission assets to form Transcos, such as capital gains taxes on sales of assets,[152] the Commission (NOPR at P 43) proposed to include in the rates of Transcos an adjustment to recover ADIT. This incentive would provide the assurance of recovery in rate base of adjustments for taxes associated with asset sales, thereby reducing uncertainty.

b. Comments

243. Several Commenters[153] submitted comments that generally support the Commission continuing to consider proposals to include adjustments for ADIT in rates when a Transco is purchasing transmission facilities. For example, Trans-Elect states that continuing to allow adjustments for ADIT will eliminate this tax-related disincentive and, in the process, demonstrate to potential sellers, purchasers and the investment community the Commission's commitment to promoting independent stand-alone transmission businesses. National Grid states that allowing recovery of ADIT is designed to ensure that there is no financial or tax penalty associated with undertaking the transactions necessary to form Transcos and therefore the Commission should allow such recovery to eliminate an obstacle to Transco formation. OMS states that allowing the ADIT cost recovery adjustment appears more reasonable than simply authorizing filings

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[152] See, e.g., International Transmission Co., 92 FERC ¶ 61,276 at 61,915-16 (2000) (explaining potential disincentives to sellers and buyers of transmission assets if the ADIT adjustment is not granted).

[153] E.g., International Transmission, KKR, National Grid, NorthWestern, OMS, PJM TOs, TAPS, and Trans-Elect.

to recover acquisition premiums because the ADIT adjustment premium would be specifically quantifiable and tied to a specified purpose. International Transmission and Trans-Elect also specifically support the Commission's clarification that a stand-alone transmission company that requests an incentive ROE would not be precluded from also requesting the ADIT adjustment.

244. Some commenters raise specific concerns regarding how an ADIT adjustment will be calculated. TAPS states that after the seller is held harmless for its book-based gain-on-sale tax consequences (if any) any remaining tax balance should flow back to ratepayers. TDU Systems state that the ADIT adjustment should be reduced by the seller's ADIT and investment tax credits associated with the transferred property. APPA is concerned about the difficulty a buyer of facilities will have in correctly calculating the ADIT, which is based on the *seller's* capital gains tax liability. NRECA states that the Commission needs to create sufficient safeguards to prevent double recovery. TAPS and APPA also cite the American Jobs Creation Act of 2004 as substantially mitigating, and potentially eliminating the ADIT concern.

245. APPA, PPC and Snohomish state that, in order to get the ADIT adjustment, buyers of transmission facilities should need to demonstrate concomitant customer benefits to offset increased transmission rates resulting from measures to recover capital gains tax-related acquisition premiums.

246. PPC and Snohomish state that allowing recovery of ADIT goes beyond the stated goal of promoting investment in new transmission capacity, and. instead would promote

the sale of existing transmission assets. They contend that allowing purchasers to amortize ADIT in rates will increase ratepayer costs and allow Transcos to benefit from the time-value of money without offsetting any actual expenditure. The value of ADIT should be passed through to customers only if the Transco is actually making tax payments, and then only in an amount equal to those payments.

c. Commission Determination

247. We find that it is appropriate for the Commission to continue to consider proposals to make an adjustment to the book value of transmission assets being sold to a Transco to remove the disincentive associated with the impact of accelerated depreciation on federal capital gains tax liabilities. This adjustment is simply intended to remove a disincentive to Transco formation. As explained in the NOPR, transmission owners are unlikely to sell transmission assets at book value if they are not held harmless from capital gains taxes on such sales by including an adjustment for taxes associated with those sales. Buyers of transmission assets may be unwilling to pay such an adjustment without some assurance of recovery of the adjustment in their rate base, as the Commission has addressed in previous Transco-related orders. In addition, we find appropriate the clarification proposed in the NOPR that a Transco requesting an incentive ROE not be precluded from also requesting the ADIT adjustment.

248. While the Commission will continue to consider proposals to include adjustments for ADIT in rates when a Transco is purchasing transmission facilities, we emphasize that we will review such proposals on a case-by-case basis to ensure that the ADIT

adjustment is just and reasonable and not unduly discriminatory or preferential under the particular circumstances of the proposal.[154] Specific concerns about how the ADIT adjustment is calculated, such as those raised by TAPS, TDU Systems, APPA and NRECA, can be raised when a proposal is filed with the Commission. In addition, TAPS' and APPA's concern that the American Jobs Creation Act of 2004 may eliminate the need for an ADIT adjustment can be raised as an issue concerning an applicant's proposed ADIT adjustment in a specific proceeding. We note that, as there is no sunset date for the incentives, applications could be made after the potential tax benefits of the American Jobs Creation Act have lapsed, as the tax law only affects transactions that close by January 1, 2007.

249. We will not require, as requested by APPA, PPC and Snohomish, that our approval of any ADIT adjustment be conditioned on an analysis of costs and benefits related to such an adjustment, as discussed elsewhere in this Rule. We disagree with the implication of PPC that the Transco purchaser is receiving the benefit for ADIT costs that it is not really paying. ADIT is part of the purchase price of the transmission assets sold to the Transco, and hence represents actual costs to the purchaser.

250. However, as described more fully in the Performance Test section, we clarify that continuation of the ADIT adjustment, like continuation of other incentives, is conditional

[154] As discussed elsewhere in the Final Rule, an applicant may propose a number of incentives. Thus, a stand-alone transmission company is not precluded from requesting ROE and ADIT.

on the applicant achieving benchmarks for its own proposed Commission-approved metrics.

4. Acquisition Premiums for Transco Formation

a. Background

251. The NOPR (at P 55) requested comments on whether the Commission should make a generic determination that general benefits would accrue to ratepayers as a result of Transco formation. It also sought comment on whether any change in the acquisition premium/ratepayer benefits review at the federal level would risk increased resistance to such acquisitions at the state level. The NOPR sought comment on whether there are other mechanisms that the Commission could institute to provide regulatory certainty of the recovery of the acquisition premium both through retail as well as wholesale rates. It also sought comment on what measure the Commission might use in evaluating the appropriateness of such premiums as measured against, for example, the size of the premium, the location of the assets, the level of independence of the Transco, and other relevant factors.

b. Comments

252. Several Commenters[155] support a generic Commission determination that Transco formation benefits consumers and that fair value paid for transmission assets by a Transco will be recoverable, even if that fair value exceeds the book value of those assets

[155] E.g., International Transmission, KKR, and Trans-Elect.

by a significant amount. Trans-Elect argues for a case-by-case consideration, i.e., that a Transco should be entitled to make a showing that the benefits of a particular transaction justify allowing a specific acquisition adjustment and that the level of proposed adjustment is appropriate. KKR supports allowing a Transco Applicant to recover an acquisition premium in rates for all or a portion of any premium paid above net book value for purchases of transmission facilities. PNM encourages the Commission to eliminate its historical prohibition against recovery of acquisition adjustments for transmission assets.

253. Several commenters[156] oppose a generic determination regarding the allowance of acquisition premiums for Transcos, and generally support the continuation of current Commission policy which, according to commenters, is case-by-case. They also oppose the Commission making a general determination that Transco formation results in general benefits to customers for purposes of determining whether to allow recovery of an acquisition premium in rates.

254. In response to our request for comment on what measure to use to evaluate the appropriateness of such premiums, Pennsylvania Commission states that if the Commission determines that approval of acquisition adjustments is necessary to encourage acquisition and mergers of transmission systems in a business-neutral way, the

[156] E.g., Ameren, APPA, MISO States, Northwestern, NRECA, Pennsylvania Commission, PEPCO, PJM TOs, Snohomish, TDU Systems, and WPS.

Commission should require applicant(s) to demonstrate that such costs were both reasonable and negotiated at arms' length. According to the Pennsylvania Commission, the applicant should be required to offer proof that the purchase price of assets had a reasonable relationship to the market valuation of the assets transferred, that the buyer and seller were financially separate and unrelated, and that directors and officers of, and advisors to, the buyer and seller had a financial and legal "arm's-length" relationship before and after consummation of the acquisition. International Transmission suggests that recovery of the difference between book value and fair value, as represented in a proposed purchase price, be limited to no more than 50 percent of any amount paid above the book value of the assets, in order to provide market discipline with respect to the purchase price of the assets. Snohomish states that there must be a means to independently verify the purchase price, such as requiring submission of two or more independent appraisals.

255. Dairyland supports limiting acquisition adjustments to situations where the seller of the facilities to a Transco does not have (or does not simultaneously obtain) an ownership in the Transco. AEP, PJM TOs and SCE state that if the Commission allows recovery of acquisition premiums, it should allow all business models to recover them, including traditional investor-owned utilities.

256. TAPS and TDU systems argue that entities allowed to recover acquisition premium for the formation of Transcos should not also be authorized to receive an enhanced ROE.

257. Nevada Companies state that the Commission must work with state regulatory authorities to foster Transco formation since transmission owners' incentives are reduced if they must give a large portion of an acquisition premium back to customers.

c. Commission Determination

258. We will not in this Final Rule change the Commission's policy of allowing acquisition adjustments in rates only upon a specific showing of ratepayer benefit.[157] However, given the positive contributions of Transcos on transmission investment discussed above, we find that a Transco may propose an acquisition premium as an incentive under the Final Rule, as provided under § 35.35 (d)(1)(viii). We will continue to evaluate proposals made by Transcos to recover acquisition premiums associated with the purchase of transmission facilities on a case-by-case basis. We appreciate the comments on how the Commission should evaluate the level of acquisition premiums, such as those from Pennsylvania Commission, International Transmission, and Snohomish, and we will take such factors into account in evaluating whether to allow recovery of particular acquisition premiums. While this discussion is limited to providing an incentive for Transco formation, entities other than Transcos can apply for

[157] While the proposed ADIT incentive discussed above would adjust book value and therefore may be considered a premium on net book value, we note that unlike the acquisition premium discussed here, the proposed ADIT incentive addresses tax-related issues outside of the applicant's control.

the incentive and the Commission will evaluate those applications on a case-by-case basis.

5. <u>Merchant Transmission</u>

a. <u>Comments</u>

259. LIPA states that because of the NOPR's focus on cost-of-service ratemaking, it has less impact on merchant transmission developers, whose rates are defined by contract (and thus market benefit), and not by Commission cost-of-service ratemaking standards. Merchant transmission developers are generally required to rely on market rates for transmission service negotiated directly with purchasers of their capacity, and to assume (along with the purchasers of their capacity) all of the market risk for their facilities. Merchant transmission developers will base their decisions on other factors, particularly their ability to efficiently attain the market benefits that their investments create.

260. TransCanada believes that a two-tier subscription process would provide merchant developers with some initial regulatory and business certainty by addressing the initial up-front siting and permitting risk (because of the ability to secure meaningful commitments from the first tier subscribers). It would also allow for a full open season for the remainder of the capacity (the second tier) consistent with current Commission policy.

261. National Grid states that the key issues raised in this rulemaking (ensuring adequate returns on equity for investment and independence, facilitating timely and

complete cost recovery, etc.) are regulated rate issues, which should be of no concern to merchant transmission developers.

b. Commission Determination

262. With respect to comments on merchant transmission, we agree with comments that this issue is beyond the scope of this Final Rule. Merchant projects are market driven while this final rule deals fundamentally with regulated transmission rates. True merchant transmission projects may play an important role in the future of transmission infrastructure development, but incentives related to, for example, ROE and cost recovery, do not apply to merchant transmission.

D. Performance-Based Ratemaking

1. General Comments

a. Background

263. In the NOPR, the Commission sought comments on ways performance-based ratemaking (PBR) might apply to for-profit Transcos and traditional public utilities, and not-for-profit Transcos and public utility ISOs and RTOs. In the case of for-profit entities, the Commission sought comment on whether there should be mechanisms for sharing gains with ratepayers and, if so, what those mechanisms should be. In the case of not-for-profit public utility ISOs and RTOs, the Commission sought comment on whether and how PBR developed for for-profit entities might be applied to not-for-profit entities. Finally, the Commission sought comment on whether performance-based benchmarks for

transmission costs would provide incentives for the deployment of advanced technologies.[158]

b. Comments

264. Commenters generally support the concept of PBR, especially as it was defined in the Commission's 1992 Policy Statement on Incentive Regulation and in Order No. 2000, which emphasize that PBR should be voluntary, have both an upside and downside, that gains should be shared with ratepayers, that benefits should be quantifiable, and that costs to consumers under PBR should not exceed what they would have been under traditional regulation. They urge the Commission to retain these principles.[159]

265. However, citing to current market structure, most commenters expressed a general lack of enthusiasm for PBR, and none held out any expectation that PBR would have a significant role to play in providing consumer benefits. Chief among the obstacles cited to implementing PBR is a difficulty in determining appropriate performance measures or benchmarks. For example, KCP&L emphasized that experts, such as EPRI, are researching appropriate performance measures but have not yet determined how to account for various factors such as system age and configuration, geography and customer density, a point of view shared by many.[160] Moreover, APPA cautions that

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[158] NOPR at P 58.

[159] E.g., NASUCA, TDU Systems, Missouri Commission, and SMUD.

[160] E.g., Comments of KCPL, SCE, and EEI.

poorly designed performance measures could lead to unintended and undesirable consequences, and it recommends that the Commission conduct a series of technical conferences and workshops on PBR before considering any implementation. The Kentucky Commission states that performance-based benchmarks for transmission costs are not necessary because any technology that is beneficial will have an economic reward, thereby providing its own incentive. The transmission tariff should reflect prudent operation and maintenance so that, if there is improvement, a greater profit will be realized. For proven technologies, a sharing of both benefits and the risks would be appropriate for deployment of new technologies. Thus, many conclude that the value of PBR seems remote, although voluntary programs could be worth considering.

266. Some commenters oppose PBR because they believe it could deter investment in transmission facilities, contrary to the main objective of the proposed rulemaking. For example, International Transmission concludes that PBR might play a limited role in some circumstances, but warns that some PBR approaches, such as price cap regulation, could actually discourage investment. Others, such as FirstEnergy and Nevada Companies are concerned that PBR could increase risk and, thus, reduce investment. Some commenters believe that PBR might have a limited role in inducing utilities to adopt certain innovative practices and advanced technologies,[161] while other commenters

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[161] E.g., Comments of AEP and UTC Power.

were more concerned that PBR would discourage reliability and provide unwarranted benefits to utilities.[162]

267. Few commenters see any realistic role for PBR as a means of inducing cost saving behavior on the part of non-profit entities, although some, such as Ameren, believe that the Commission's oversight is inadequate. Industrial Consumers, in particular, express the view that PBR has no role to play in the non-profit area and, furthermore, that PBR should not be applied to the profit area unless a proven model would make pricing under PBR as transparent as pricing under conventional ratemaking. Some commenters[163] stress that safeguards already exist to insure that ISOs/RTOs are efficient and accountable, and they argue that there is no urgency to adopt PBR for RTOs/ISOs. Although they could consider PBR on a limited, case-by-case basis, PJM TOs also emphasize that RTOs with regional planning processes and requirements outside the transmission owners' control are poor candidates for PBR.

268. Among those commenting most favorably on implementing some form of PBR were Progress Energy, Southern Company, and National Grid. Although they see limited immediate applicability of PBR, both Progress Energy and Southern Company recommend specific types of PBR – Progress Energy favors loop flow pricing, and Southern Company favors revenue or rate caps that would reward utilities for increasing

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[162] E.g., Comments of NSTAR and the New Mexico AG.

[163] E.g., NYISO, CAISO, PJM TOs and NECOE.

throughput. In contrast, National Grid emphasizes that it has had success with PBR mechanisms different from those mentioned in the NOPR outside the U.S. However, until the U.S. industry is more independent and there is greater consolidation of ownership and operation, it does not believe that PBR is an immediate attractive option.

269. Connecticut DPUC, along with testimony submitted by two of its witnesses, Thomas P. Lyon and Pete Landrieu, support the view that PBR is either inappropriate or unlikely to provide important benefits. Lyon's affidavit emphasizes that critical principles for PBR include not only incentives to enhance efficiency and performance, but also should promote an efficient mix of infrastructure investment. He cautions against the use of price caps because they may induce firms to degrade quality, and he would favor some type of profit-sharing plan, perhaps a PBR that links a firm's financial performance to network congestion.[164] Landrieu's affidavit emphasizes that PBR is unnecessary, because system standards and performance are better managed directly by various regional reliability organizations. He also is pessimistic that PBR focused only on transmission will be able to account for important and complex tradeoffs between generation and transmission. He agrees with other comments that note that establishing appropriate benchmarks is an extremely complicated task and for that reason regards benchmark type PBR as unworkable.[165]

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[164] Comments of Connecticut DPUC, Affidavit of Thomas P. Lyon at 16-19.

[165] Comments of Connecticut DPUC, Affidavit of Pete Landrieu at 27-28.

c. Commission Determination

270. We interpret "incentive-based (including performance-based) rate treatments" in section 219 to require the Commission to consider PBR as an option among incentive ratemaking treatments. To that end, the NOPR invited comments on how performance-based regulation might be used to motivate transmission entities to maintain and operate their systems reliably and efficiently. Consistent with Congress' directive to encourage PBR, we signaled our intention to reevaluate previous Commission policies on PBR. We did not intend that the NOPR be viewed as a rejection of our previous statements or as a comprehensive overview of all possible approaches to PBR. Our objective was to consider whether PBR can play a useful role in transmission pricing reforms in light of the many changes in electric markets that have occurred since our earlier statements.

271. The overwhelming view on PBR from all segments of the industry is "not at this time" and "not given the current industry structure." Although there is general support for our earlier principles, we acknowledge, as commenters stress, that our voluntary program has not resulted in any PBR proposals being filed with the Commission. The consensus appears to be that the current state of the industry structure – a multitude of transmission-owning entities, many that do not directly control their transmission assets and operate in diverse geographical regions with very different customer densities, system ages and configurations – makes the determination of generally applicable performance benchmarks unworkable. Some suggest further study of PBR, express

general support for the concept, and urge the Commission to remain open to considering voluntary proposals on a case-by-case basis.

272. We share the view of most commenters that it would be premature to adopt generic PBR measures at this time. However, the development of PBR measures may represent a long-term goal for the industry and the Commission to pursue. Among the goals of section 219 is to promote capital investment "in the enlargement, improvement, maintenance, and operation" of transmission facilities. Accordingly, we intend to continue to work with the industry to encourage development of PBR proposals.

2. Comments Proposing Performance Tests and Competitive Bidding

a. Comments

273. The New Mexico AG asserts that another way to implement an incentive-based mechanism is to penalize companies or RTOs that do not perform adequately and do not make the investments necessary to ensure the reliability of the transmission grid. The Delaware Commission contends that providing incentives without assessing penalties for failure to meet obligations violates the just and reasonable standard because it rewards monopoly power. Furthermore, the Delaware Commission claims that the plain meaning of incentive requires both rewards and penalties. NASUCA states that it is one-sided and inherently unfair to provide incentives that only increase utility profits with no performance accountability.

274. The Delaware Commission recommends that the Commission implement performance penalties by first defining the utility obligation, then determining whether

there are transmission incentive projects which the transmission owner has failed to carry out, and in such situations impose a penalty in the form of a prospective reduction in return on equity or prudence disallowance that can be lifted when the project is complete.

275. TAPS argues that transmission providers should have their returns reduced to the low end of the zone of reasonableness if they fail to achieve and maintain a robust transmission infrastructure. TAPS recommends the Commission consider a number of factors in its determination of system reliability, including congestion, proration of financial transmission rights (FTRs), lack of available transfer capacity (American Transmission), failure to meet customer needs and denial of reasonable access. TAPS also asserts that the capital requirements of major projects should be put out to bid if a vertically-integrated transmission owner is unwilling to permit transmission dependent utility (TDU) participation but refuses to build without receiving above-cost rate treatments.

276. The Missouri Commission proposes that the Commission implement a process that determines performance-based ROEs. The process, according to the Missouri Commission, would require transmission owners to bid out projects, thereby providing an incentive for keeping implementation costs as low as possible and minimizing the regulatory concern with cost overruns. Projects based on actual costs would receive an ROE below the median of ROEs from the proxy group while projects proposing fixed costs would receive higher ROEs, explains the Missouri Commission. The Missouri Commission also recommends that the bids include an assessment and quantification of

specific risks associated with the project. E.ON US would support a competitive bidding process for transmission additions required to enhance reliability or to meet native load requirements.

b. Commission Determination

277. As discussed in the preceding section, the Commission will continue to support industry in the development of PBR but will not in the Final Rule impose it. Accordingly, we will not pursue performance treatments and competitive bidding. Moreover to the extent these proposals consist of penalties (which would not provide incentives to expand transmission infrastructure and would likely limit the investment in infrastructure by reducing the return – and therefore funds for capital expansions), they do not implement the requirements of section 219.

278. We note that the Commission has other regulations to address concerns over access and discrimination raised by commenters, including rules promulgated under Order No. 888, the anti-manipulation provisions of Order No. 672[166] and market behavior rules. We believe those regulations provide adequate protections. Further, all rates that include incentives will remain in the zone of reasonableness, and, therefore, we disagree with the Delaware Commission that rates without penalties are not just and reasonable.

[166] Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards, Order No. 672, 71 FR 8662 (Feb. 17, 2006), FERC Stats. & Regs., ¶ 31,204 (2006), order on reh'g, Order No. 672-A, 71 FR 19,814 (Apr. 18, 2006), FERC Stats. & Regs. ¶ 31,212 (2006).

279. While the requirements of section 219 and the Final Rule do not encompass bidding processes, as recommended by the Missouri Commission and TAPS, we are sympathetic to the objective of the Missouri Commission to reduce the costs of expansions to consumers. We expect that regional planning processes that evaluate and compare the costs and benefits of expansion proposals, as well as state commission reviews and requirement that costs be prudently incurred will serve to provide the screening function desired by the Missouri Commission, and therefore additional processes are not necessary. We agree with NASUCA that there is merit in holding utilities receiving incentives accountable for investing the capital and building the capacity for which the incentives are provided, as we discuss further in section IV.A (Standard for Approval) and section III.D (Effective Date and Duration Of Effectiveness For Incentives). As we discuss further below in section IV.H (Public Power), we will not make TDU participation in the project a precondition for receiving incentives.

E. Advanced Technologies

1. General

a. Background

280. Pursuant to section 219(b)(3) of the FPA, the NOPR proposed to encourage the use of advanced technology in new transmission projects. Advanced transmission technologies are defined in section 1223 of EPAct 2005 to be technologies that increase

the capacity, efficiency, or reliability of an existing or new transmission facility.[167] The Commission stated that it expected that the NOPR's proposed incentives, including the ROE-based incentives, will stimulate investment in new transmission facilities, which will, in turn, provide opportunities for the deployment of innovative technologies for those new transmission facilities.

281. The NOPR also asked for comments on: (1) whether the Commission should require that applications for incentive-based treatment include a technology statement; (2) whether other incentives could fulfill the goals of section 219(b)(3); and (3) whether performance-based benchmarks for transmission costs (i.e., a risk-sharing approach) would provide incentives for the deployment of advanced technologies.[168]

b. Comments

282. NRECA and others support the incentives proposed in the NOPR and do not support additional separate incentives for advanced technology. They believe that technologies will be developed when they are cost effective.

283. NEMA believes the technology list from section 1223 of EPAct2005 should be incorporated into the Final Rule to ensure that the Commission's regulations express the intent of Congress. But, EEI argues that a predetermined list of advanced technologies

[167] Section 1223 identifies 18 such technologies and further provides that advanced transmission technologies include any other technologies that the Commission considers appropriate.

[168] NOPR at P 64-66.

would soon become outdated, which may discourage the use of other worthwhile technologies. Bonneville states that the list in the NOPR is incomplete and includes items that range from measures in common use today to very speculative items. AEP believes that any list of advanced technology should be illustrative and non-exclusive.

284. AEP and others want the Commission to encourage additional measures related to reliability and infrastructure development, including control center upgrades, national security-related infrastructure facilities vital to the electric system and operation, the refurbishment of aging transmission assets, advanced grid control technologies for real-time measurement, communications and control, "non-wires" alternatives to control or dispatch loads and resources for optimum use of the transmission and distribution infrastructure, inventories of transformers and other critical equipment, and substation upgrades.

285. Some commenters seek incentives for technologies that could indirectly mitigate congestion and enhance grid reliability. UTC Power believes the Commission should provide incentives for distributed generation, such as fuel cells. Sabey believes that advanced technology usage on the distribution system may provide transmission congestion relief. FirstEnergy suggests incentives for pumped storage hydro and compressed air energy storage.

286. NSTAR and Vectren urge the Commission to recognize the higher risk caused by accelerated obsolescence of transmission facilities. Obsolescence may be the result of the changing transmission technology. Accelerated depreciation could be relevant to a

specific facility that may have a useful life less than its physical life due to obsolescence.

287. Some commenters, such as International Transmission, state that it is imperative that new technology installed on the grid be reliable and durable for decades. They express concern that new technologies may carry significant risks and may ultimately not be low cost and reliable.

c. Commission Determination

288. We agree with comments that new technologies will be adopted when they are cost effective. Incentives will be considered for advanced technologies through the same evaluation process as other technologies, as discussed in this Final Rule.

289. We will not provide a unique incentive designed for a specific technology. To the extent that applicants seek additional incentives for advanced technologies, the Commission will consider the propriety of such incentives on a case-by-case basis.

290. Section 1223 of EPAct 2005 lists 18 advanced transmission technologies. We interpret this list as being illustrative of the kinds of technologies that Congress sought to encourage and not exclusive of advanced technologies that may be employed and considered for incentive ratemaking treatment. We expect new technologies to continually evolve. Moreover, as noted above, section 1223 of EPAct 2005 also provides that advanced transmission technologies include any other advanced transmission technologies that the Commission considers appropriate. Thus, we decline to adopt in the regulatory text a specific list of technologies eligible for incentive ratemaking, and

will entertain proposals for incentives rate treatments for advance technologies on a case-by-case basis.

291. This includes technologies that may indirectly mitigate congestion and enhance grid reliability, if such technologies can be shown to increase the capacity, efficiency, or reliability of an existing or new transmission facility.

292. The Commission does not have sufficient information to make generic judgments about what barriers exist, if any, to the introduction of particular technologies based on the record. To the extent applicants believe additional incentives for advanced transmission technologies are needed, they must support such requests in individual cases.

293. In addition, we note that those applicants that do not want to use accelerated depreciation for all their facilities may elect to utilize this incentive for advanced technologies since the useful life of such technologies may not be sufficiently known. The Commission will also consider requests to recover the costs of obsolescent plant, thereby facilitating the addition of new, more technically advanced transmission infrastructure.

2. Case-by-Case Review

a. Comments

294. Ameren and others suggest the Commission should determine whether technology applications are just and reasonable on a case-by case basis, which would allow

applicants flexibility to determine which technologies are best suited for a particular project.

295. National Grid believes the Commission should encourage the development of the best technology for particular needs identified in transmission owners' planning processes. This avoids putting the Commission in a position of picking winners and losers, but would allow transmission owners to make appropriate decisions relative to costs, benefits and risks associated with advanced technologies.

296. International Transmission suggests the Commission should determine what incentives are necessary to overcome barriers to deployment of the technologies defined in section 1223 of EPAct 2005, and then authorize those incentives on a case-by-case basis.

297. As an alternative to the case-by-case consideration of incentives, AEP recommends establishment of criteria for transmission investment to receive full incentive treatment. Such criteria might include: reducing congestion, advancing growth and security of the interstate grid, and providing an opportunity to site fuel diverse, newer technology, and environmentally friendly generation.

b. <u>Commission Determination</u>

298. The Commission will consider incentives for advanced technologies on a case-by-case basis. As discussed above, we are not making generic determinations regarding the applicability of incentives to particular technologies. Consistent with this case-by-case approach, we will not adopt AEP's suggestion to establish generic criteria for evaluating

which transmission investments will receive full incentives. As discussed by Ameren and others, case-by-case review also provides flexibility to transmission providers in identifying the technologies that are most appropriate for their project applications and business models. It also avoids putting the Commission in a position of picking winners and losers, but allows transmission owners to make appropriate business decisions, as discussed by National Grid. The Commission in its reviews will provide incentives to technologies that increase the capacity, efficiency, or reliability of an existing or new transmission facility.

299. With regard to International Transmission's concerns, the Commission is not in a position to make generic judgments about what barriers exist, if any, to the introduction of particular technologies. To the extent applicants believe additional incentives for their advanced technology applications are needed, they can make a case for advanced technology incentives in their individual proceedings and the Commission will make a case-by-case determination.

3. Whether To Require A Technology Statement

a. Comments

300. TAPS and others believe the Commission should not require that a particular technology or the most advanced technology be used in order to qualify for incentives. They believe that a technology statement would add an unnecessary burden to applications and would likely result in Commission approval of imprudent and routine transmission investment. They also argue that statements made by an applicant would

tend to be self-serving, and not detailed enough for proper Commission evaluation. Instead, the Pennsylvania Commission suggests that the Commission develop in-house technology expertise, or alternatively establish a peer review board of nationally recognized independent experts.

301. UTC Power believes the technology statement should also include a list of the advanced technologies capable of meeting the project goals for reducing congestion and increasing reliability, and reasons they were not employed. Duquesne supports a technology statement but does not believe that it should have to be specific as to describe all technologies that were considered and not used.

b. Commission Determination

302. In as much as EPAct 2005 requires the Commission to encourage the deployment of transmission technologies, we will require applicants for incentive rate-treatment to provide a technology statement that describes what advanced technologies have been considered and, if those technologies are not to be employed or have not been employed, an explanation of why they were not deployed.

4. Risk Sharing

a. Comments

303. CCAS suggests that the Commission offer a framework of cost sharing among entrepreneurs, ratepayers, utility shareholders and taxpayers, peer review and competitive solicitation to share and recover qualified research development and demonstration project costs through transmission rates. NEMA supports performance-based ratemaking

as a means of enabling advanced technology implementation for the sharing of benefits and risks between utilities and customers.

304. CAISO suggests that the Department of Energy and the Commission cooperate with the industry and reliability organizations on programs to identify, test, and disseminate information on new technology. APPA also suggests a process for the Commission to work with each region to develop a technology plan and a research and development budget, with costs to be recovered through regional transmission rates. Sabey encourages the Commission to provide incentives for technology demonstrations on small-to-medium scale projects.

305. NU and others suggests the Commission consider incentive ratemaking treatment of research and development dollars spent by utilities, which benefit the advancement of new technology. The Kentucky Commission believes in federal funding for research and that the Department of Energy is an appropriate sponsor for research in new transmission technology.

306. EPRI supports efforts to enhance grid infrastructure, and offers a list of advanced transmission technologies that are near term or commercially available, those that may be available for demonstration within four months with commercial availability in three to five years, and longer-term technologies still in the research and development stage with possible demonstration in three to five years.

b. Commission Determination

307. The Department of Energy is a more appropriate federal agency to promote research and development. Accordingly, research and development are beyond the scope of this proceeding, and we will not include incentive ratemaking for research and development costs in the Final Rule.

5. Other Technology-Related Issues

a. Comments

308. Semantic states that the Final Rule needs to define "prudently-incurred" costs that are to be recoverable and proposes that "prudently-incurred" be defined to include a substitution test such that expenditures are not made in excess of that which is required. By way of example, Semantic offer that an open RFP process for congestion relief should provide for separate pricing for the avoided cost value of each separable reliability benefit for which the reliability standards require action. This separate pricing of strategies for achieving the reliability and congestion goals must be compared to the summed cost of the advanced technology that can achieve the goals when determining prudence and just and reasonable rates. Semantic believes that such an approach results in greater efficiency in the use of the existing grid and the Final Rule should provide incentives other than ROE adders to foster such efficiency through the use of Advanced Transmission Technologies for time of day congested segments of the grid.

309. American Superconductor states that the Commission should revisit and clarify its Seven Factor Test for distinguishing between transmission and distribution facilities, to

reflect technology advances made since the Commission adopted the Seven Factor Test. For example, American Superconductor states that it has developed dynamic VAR technologies that can effectively support transmission grids while connected to distribution facilities. Classification of such advanced technologies as transmission facilities would make them eligible for recovery under Commission-jurisdictional tariffs.

b. Commission Determination

310. We deny Semantic's request to define "prudently-incurred" as requiring an open RFP process to consider alternative technologies and to provide additional incentives to address time of day congestion. As previously stated, we expect that new development programs will include, or at least consider, advanced technologies, but we will not mandate it. We agree that improvements in the operation of the grid, perhaps through advanced technologies addressing time of day congestion, could result in efficiency benefits and encourage such proposals on a case-by-case basis.

311. We also deny American Superconductor's request to revisit our Seven Factor Test because it is beyond the scope of this proceeding.[169]

[169] We note that if these technologies truly perform a transmission function, a more productive approach than modifying the Seven Factor Test may be to propose modification of the Uniform System of Accounts to reflect such plant in a new transmission-related plant account. But that is beyond the scope of this proceeding.

F. Transmission Organization Incentive

1. Background

312. The NOPR (at P 45) proposed that the Commission will continue to consider requests for ROE-based incentives for utilities that join an RTO, in recognition of the benefits such organizations bring to customers, as outlined in detail in Order No. 2000. In addition, it proposed that the Commission will consider similar requests by utilities that join an ISO for an incentive ROE that, while still in the zone of reasonableness, is higher than the ROE the Commission might otherwise allow if the utility did not join.

313. The NOPR (at P 46) also sought comment on whether the Commission should consider incentive-based ROE requests for public utilities that are not in an RTO but that join a Commission-approved regional planning organization.

2. Comments

314. Comments span a wide range of views on proposed incentive for utilities that join an RTO. Several commenters[170] support the proposal to continue to consider requests for ROE-based incentives for utilities that join a Transmission Organization. Most of these commenters also request that the incentive apply equally to both new members and existing members. They contend that denying an incentive to existing Transmission Organization members while awarding it to new members who join these organizations

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[170] E.g., Ameren, EEI, Electric Power Supply, FirstEnergy, KCPL, MidAmerican, National Grid, NYSEG, NorthWestern, New England TOs, NSTAR, PEPCO, PacifiCorp, PG&E, PJM, PJM TOs, TransCanada, Trans-Elect, Vectren, and WPS.

unfairly discriminates against those entities that should be rewarded for taking the initial step of establishing and joining an independent Transmission Organization and would therefore be contrary to good public policy, unjust, unreasonable, and unduly discriminatory. In addition, this discrimination could create an incentive for a transmission owner to depart from an existing RTO and to join a new RTO, simply to obtain the NOPR incentives "for public utilities that join a Transmission Organization." PEPCO states that an adder should apply generally to all facilities for utilities in the RTO, not just to new investment after a new company joins an RTO.

315. Other commenters[171] contend that, if the Commission does allow an incentive for joining a Transmission Organization, the incentive should only apply going forward for new members, not for those who already joined. They argue that incentives should incite or spur a desired future action, and thus it makes no sense to provide incentives to transmission owners for past behavior or for actions that are likely to occur under other normal business circumstances. Incentives for existing members would represent an unjustified windfall for utilities, at the expense of the transmission customers. In addition, the FPA does not permit the Commission to reward a utility "in recognition" of benefits for actions already taken by the utilities.

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[171] E.g., Connecticut DPUC, Dairyland, Delaware Commission, NRECA, NECOE, NECPUC, New York Commission, SMUD, TANC, MISO States and TDU Systems.

316. Some of these commenters also assert that the incentive should not apply where a transmission owner is ordered to join a RTO/ISO by statute or has agreed to join an RTO/ISO as a condition of receiving approval for a merger, market-based rates, or because of other regulatory actions. Also, possible incentives for joining an RTO, and the procedures for requesting such incentives, are already addressed in Order No. 2000.

317. Certain commenters[172] contend that the Commission should consider giving ROE incentives only to companies joining a newly forming Transmission Organization, rather than existing ones, and then only for a limited period of time; and if a public utility withdraws from an RTO or ISO for which it obtained an ROE adder for joining, the Commission should issue an order immediately eliminating such ROE adders.

318. Others request that the Commission make a generic finding that entities that join an ISO or RTO automatically qualify for the incentive. For example, Trans-Elect submits that the Commission can and should use the record developed in this proceeding to find, on a generic basis, that RTO/ISO membership produces sufficient customer benefits to qualify for the 50 basis-point ROE adder.

319. Some commenters[173] state that this incentive should not be limited to public utilities. It should apply to all transmitting utilities and electric utilities, including municipal utilities. Another view, that of Northwestern's, would have the Commission

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[172] E.g., MISO States, NRECA, and TDU Systems.

[173] E.g., CAISO, APPA, and NRECA.

consider granting such incentives to transmission owners that are actively engaged in the development of an RTO or ISO, and permit transmission owners to recover prudently incurred costs of developing an RTO or ISO as they are incurred, in regions that do not currently have such an independent entity. American Wind strongly supports the objective to regionalize the grid, but believes that it would not serve the Commission's or Congress' goal to allow incentives to any type of Transmission Organization that is approved by the Commission for the operation of facilities. For example, American Wind states that single-system Transcos do nothing for regional goals.

320. Some commenters raise issues concerning the definition of a Transmission Organization. For example, Bonneville and PNM believe that incentives should be available to utilities that enter agreements or form transmission associations outside the specific models of RTOs or ISOs. MISO States contend that the Commission should not grant ROE incentives to utilities joining Transmission Organizations until these entities are more clearly defined. MISO States assert that the Commission currently has inadequately specified standards and requirements for "independent transmission providers" and no established standards or requirements for "other transmission organizations."

321. Some commenters seek some type of conditions/criteria for receiving the Transmission Organization incentive, including: ongoing participation in an ISO that provides open access on the basis of competitive bids and that allocates the costs of grid access to users based on LMP ; participation in the relevant ISO or RTO planning process

such that the ISO or RTO will make a determination of need; or tying the incentives to whether the Transmission Organization has an effective regional planning process that results in the construction, not merely the identification, of transmission. Others suggest tying the level of the incentive to meeting certain criteria, including: a single sliding scale ROE adder mechanism which is tied to levels of independence; or a graduated incentive tied to important features of the Transmission Organization like degree of independence, range of functions, transparency of operations, openness of stakeholder forums, and geographic scope of the transmission planning area.[174]

322. Some commenters state that there should be penalties associated with a lack of participation in Transmission Organizations.[175] For example, they contend that: the ROE should be reflecting that service not provided by an ISO or RTO is less optimal; there should be a negative 50 basis point penalty on those public utilities that seek to withdraw from RTOs within the first 5 to 10 years of participation to recognize the costs paid by consumers to fund the public utility's participation; and there should be penalties for incumbent transmission owners that continue to frustrate RTO formation.

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[174] E.g., SDG&E, CAISO, International Transmission, National Grid, and MISO States.

[175] E.g., California Oversight Board, TDU Systems, and TransCanada.

323. Some commenters oppose ROE-based incentives for joining an RTO or ISO.[176] Among other reasons, they state that: it has not been determined whether the benefits of participation in RTOs outweigh the costs, and, therefore, there is no justification for an incentive to encourage participation in RTOs; that the incentive is unwarranted because RTOs and similar organizations have a poor track record for getting new transmission built; that return incentives for RTO participation raise the already heavy RTO cost burden and add fuel to the concerns of state commissions and customers about RTO costs, thus undermining RTOs; that the risk of joining an RTO/ISO will already be reflected in the utility's return allowance; that joining an RTO/ISO is already lucrative, a fact that can be illustrated by the sound business conditions of the existing transmission owners' businesses in an RTO/ISO area in which transmission businesses will have guaranteed returns as a monopoly business; and that the incentive is not tied to actual new investments, and allowing an increased ROE on all transmission investment (including existing facilities) would merely drive up transmission rates.

324. According to PPC, EPAct 2005 is conspicuously silent regarding whether Transmission Organizations are desirable, and section 219(c) cannot fairly be read to authorize the Commission to provide incentives to the utilities that join such organizations that are greater than those incentives that are available to other, non-member utilities.

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[176] E.g., APPA, NRECA, and TDU Systems.

325. Several commenters support incentives for participation in a regional planning process that is not necessarily an RTO.[177] For example, PJM supports incentives for transmission owners' participation in robust regional transmission planning processes as an effective, collaborative and transparent means to ensure the development of economically efficient transmission projects that truly benefit customers. MidAmerican states that a strict requirement for public utility participation in an RTO or ISO could discourage certain transmission owners, particularly non-jurisdictional transmission owners, from regional participation under any structure. Bonneville states that modest financial incentives linked to construction of new facilities advocated by an independent regional planning process may be sensible, but incentives must be tied to implementation of the regional plan, not just for mere participation in the organization.

3. Commission Determination

326. To the extent within our jurisdiction, we will approve, when justified, requests for ROE-based incentives for public utilities that join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization. However, we are not persuaded that we should create a generic adder for such membership, but instead will consider the appropriate ROE incentive when public utilities request this incentive. The decision in this rule to consider specific incentives on a case-by-case basis fulfills the

[177] E.g., Ameren, Southern Companies, SCE, PJM, and MidAmerican.

Congressional mandate to the Commission.[178] Thus, issues concerning risk such as those raised by SMUD are more appropriately addressed in the proceedings that evaluate proxy companies and set a zone of reasonableness.

327. We will not make a generic finding on the duration of incentives that will be permitted for public utilities that join Transmission Organizations. An entity will be presumed to be eligible for the incentive if it can demonstrate that it has joined an RTO, ISO, or other Commission-approved Transmission Organization, and that its membership is on-going. Any public utility receiving an incentive ROE for joining a Transmission Organization but that withdraws from such organization is no longer eligible for the ROE incentive.

328. We will not broaden or restrict the definition of Transmission Organization. For purposes of this Final Rule, and as defined in section 3(29) of the FPA, a Transmission Organization means a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities. We note that all RTOs and ISOs are already covered by this definition, and we will consider, on a case-by-case basis, applications for other types of entities to be classified as Transmission

[178] We believe that the Commission's accounting and reporting procedures for RTOs, as required by Order No. 668, address commenters' concerns about the management of RTO costs. See Accounting and Financial Reporting for Public Utilities Including RTOs, Order No. 668, FERC Stats. & Regs. ¶ 31,199 (2005).

Organizations for purposes of whether membership warrants incentives under these provisions.

329. With respect to NorthWestern's argument that the Commission should consider incentives for the development of a Transmission Organization and permit recovery of prudently incurred costs of such development as they are incurred, the Commission will review applications for incentives in the context of filings for the creation of Transmission Organizations and determine the appropriate methods for recovery of costs on a case-by-case basis. With respect to comments suggesting specific criteria to qualify for the incentive (e.g., participation in a planning process) or that the level of the incentive be tied to meeting certain criteria, we will not specify such criteria in this Final Rule.

330. Several comments urge that eligibility for these incentives not be limited to public utilities. However, the fact is that section 219(a) directs that this rulemaking provide incentives for "public utilities" and public utilities are the only entities whose rates are jurisdictional under sections 205 and 206 of the FPA. Further, although section 219(c) refers to incentives for "transmitting utilities" and "electric utilities" that join Transmission Organizations, it also contains the provision "to the extent within its jurisdiction." Accordingly, the rule will apply to jurisdictional public utilities.[179] We

[179] We note that new section 211A gives the Commission authority to order transmission services by otherwise non-jurisdictional transmitting utilities. The Commission has never exercised authority under the new provision and the new (continued)

clarify that this does not mean that public utilities are precluded from proposing incentive plans under section 205 whereby incentives would be given to public utilities as well as non-public utilities. Indeed, we encourage such plans. However, we would generally not have authority under sections 205 and 206 to enforce such incentives for the non-public utilities.

331. We also clarify that, as explained earlier, entities that have already joined, and that remain members of, an RTO, ISO, or other Commission-approved Transmission Organization, are eligible to receive this incentive. The basis for the incentive is a recognition of the benefits that flow from membership in such organizations and the fact continuing membership is generally voluntary.[180] Our interpretation of the statute is that eligibility for this incentive flows to an entity that "joins" a Transmission Organization and is not tied to when the entity joined. As some commenters note, to do otherwise could create perverse incentives for an entity to actually leave Transmission Organizations and then join another one. It would also be unduly discriminatory for the Commission to consider the benefits of membership in determining the appropriate ROE for new members but not for similarly situated entities that are already members.

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provision provides limited rate authority. However, we leave open the possibility that incentives for otherwise non-jurisdictional transmitting utilities could be permitted in an order under section 211A.

[180] Our clarification also applies to utilities that joined RTOs or ISOs because of merger conditions or market-based rate requirements.

332. We will not at this time establish a specific incentive for joining a Commission-approved regional planning organization. A regional planning process is very important to meeting regional transmission needs, and, we believe it will produce benefits for customers. For this reason, we have initiated a proposed rulemaking to require transmission providers to coordinate with interconnected systems when planning transmission system additions.[181] This increased coordination in regional planning proposed in the OATT Reform NOPR would be mandatory, not optional, and therefore we will not offer at this time an incentive for such coordination. However, if a region develops a planning processes that is superior to that required by the OATT reform rulemaking (such as by using an independent entity to perform system planning), nothing in this final rule would preclude entities in the region from requesting appropriate incentives under FPA section 219.

333. As stated earlier in this Final Rule, we will not adopt performance-based ROEs that reduce ROEs for transmitting utilities that do not join Transmission Organizations, as recommended by several commenters. The purpose of this rule is to provide incentives, per the requirements of section 219.

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[181] See OATT Reform NOPR at 214.

G. Recovery of Prudently Incurred Costs to Comply with Reliability Standards and Recovery of Prudently Incurred Costs Associated with Transmission Infrastructure Development

1. Background

a. Prudently Incurred Costs to Meet Mandatory Reliability Standards

334. Under FPA section 215 (Electric Reliability), an Electric Reliability Organization may propose, and the Commission may approve by rule or order, reliability standards.[182] Pursuant to section 219(b)(4)(A) of the FPA, the NOPR (at P 47) proposed to allow recovery of all prudently incurred costs necessary to comply with these mandatory reliability standards. Proposed new § 35.35(f) would allow for such recovery.

b. Prudently Incurred Costs Associated with Transmission Infrastructure Development

335. Under FPA section 216 (siting of interstate electric transmission facilities), the Commission has certain backstop siting authority for transmission facilities when the Secretary of Energy designates a geographic area experiencing electric transmission capacity constraints or congestion that adversely affects consumers as a National Interest Electric Transmission Corridor. Pursuant to section 219(b)(4)(B) of the FPA, the NOPR (at P 48) proposed to allow recovery of all prudently incurred costs related to infrastructure development pursuant to section 216. Proposed new § 35.35(g) would allow for recovery of such prudently incurred costs.

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[182] An Electric Reliability Organization is the organization certified by the Commission to establish and enforce reliability standards for the bulk power system, subject to Commission review. See Order Nos. 672 and 672-A.

2. Comments

336. Several commenters raise issues applicable to both the mandatory reliability standard-related incentive and the infrastructure development-related incentive. For example, PJM TOs argue that the Commission should require that recovery of such prudently incurred costs be through stand-alone section 205 filings.

337. FirstEnergy and National Grid seek clarification that the NOPR is not revising existing policy on the recovery of prudently incurred costs and that there continues to be a presumption that investment is prudently made, with the burden of the challenging party to prove otherwise.

338. NRECA requests guidance from the Commission on what it considers to be prudently incurred costs. NRECA suggests the addition of a test to determine if the costs to comply with mandatory reliability standards and infrastructure development are just, reasonable and not unduly discriminatory, and that the Commission require participation in a regional planning process, with LSE participation.

339. Some commenters proffer specific examples they believe should be considered as prudently incurred reliability or infrastructure development costs. For example, AEP recommends the cost of control centers and national security infrastructure, and Semantic recommends substation tests as reliability costs.

340. East Texas and others caution the Commission to approve only the costs that are necessary to comply with mandatory reliability standards and for transmission

infrastructure development. They express concern about the potential for rising costs to customers that may result from additional transmission investment.

341. APPA and others raise issues specific to recovery of prudently incurred costs to comply with mandatory reliability standards. APPA and other commenters agree that it is appropriate for the Commission to allow recovery of all prudently incurred costs to comply with mandatory reliability standards, and recommend the Commission clarify standards for determining that such costs are prudently incurred. TDU Systems suggest the Commission approve only prudently incurred costs to comply with mandatory reliability standards that are approved by a regional entity and in the context of a full FPA section 205 rate hearing or under a formula rate.

342. East Texas raises an issue specific to recovery of prudently incurred costs associated with infrastructure development. It requests that the Commission make explicit provisions in its transmission incentives rules for any actions that it may undertake under the new siting authority provided to it under section 216.

3. <u>Commission Determination</u>

343. The Commission will allow recovery of all prudently incurred costs necessary to comply with the mandatory reliability standards under section 215 and all prudently incurred costs associated with infrastructure development under section 216. In response to commenters, we further clarify that the Commission will review applications for the recovery of such prudently incurred costs under its section 205 procedures.

344. Some confusion may have been caused because the NOPR is more broadly

related to transmission pricing reform and expresses the Commission's willingness to consider a variety of transmission pricing "incentives" to encourage the construction of new transmission. In many instances new investment in transmission may both improve reliability and reduce congestion. However, the NOPR specifically referred to recovery of "prudently incurred costs" in the context of the section 215 and 216-related expenses and investment. We take this opportunity to clarify that we are simply codifying our long standing regulatory policy that allows utilities the opportunity to recover all prudently incurred costs associated with the provision of transmission service in interstate commerce.

345. We deny NRECA's request that the Commission require participation in a regional planning process as part of the prudence review. As we have stated earlier in this rule, we will not make regional planning a precondition of receiving incentive ratemaking treatment. However, we expect and encourage participation in regional planning processes for all major transmission additions, including those within a designated national interest corridor.

346. In regard to commenters' specific examples of what they believe should be considered as prudently-incurred reliability or infrastructure development costs, we find it premature to develop such a list of pre-approved costs without proper consideration of the equipment involved and its application to the transmission system. This type of case-specific justification would be required from the applicant in its section 205 filing.

347. Similarly, we deny APPA's request to establish standards for determining that

reliability standards compliance costs are prudently incurred. The Commission is making no change in the long-standing regulatory presumption in a section 205 proceeding that costs are prudently incurred, but parties are free to provide evidence to the contrary; and, ultimately, the burden is on the applicant to demonstrate that its proposal is just and reasonable.

348. We deny the request of East Texas that the Final Rule include explicit provisions for any actions the Commission may take with respect to the Commission's backstop siting authority under FPA section 216. This is beyond the scope of this rulemaking, which addresses only the recovery of prudently-incurred costs related to transmission infrastructure development pursuant to FPA section 216, not the Commission's backstop siting authority under that section. This issue is best addressed in the National Interest Electric Transmission Corridors proceeding in Docket No. RM06-12-000.

H. Public Power

1. Background

349. Given the importance of public power participation and the requirements of section 219, the NOPR (at P 63) requested comments on what actions the Commission should take in this rulemaking to encourage public power participation in new transmission projects. The NOPR asked, for example, whether the consortium approach would help to promote expansion of the transmission grid, and, if so, what types of incentives the Commission could provide to encourage such consortia.

2. Comments

350. Commenters express diverse views. Several commenters[183] express support for the consortium approach. For example, Connecticut DPUC states that the approach has appeal especially for very large transmission projects involving multiple states and that where there is agreement on the project, a sharing of the benefit incentives might be applicable. Similarly, Ameren and PJM state that public power involvement can be valuable and that the Consortium should receive the same incentives available to public utilities developing such projects. PJM supports a case-by-case approach for incentive rate treatment for these types of projects. EEI and MidAmerican offer that regardless of whether public power is involved, any member of the consortium should receive the same incentives that public utilities receive for building new projects. Upper Great Plains states that incentives should be available to all forms of joint projects, not just those arising from an RTO-led consortium.

351. Certain commenters[184] state that public power participation should not be mandated. New England TOs warn that requiring that utilities offer participation in transmission projects to certain pre-specified parties will be counter-productive. New England TOs state that there are other entities (e.g., private equity, merchant

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[183] E.g., Connecticut DPUC, PJM, Municipal Commenters, Semantic, Progress Energy, and Ameren Services.

[184] E.g., KCPL, National Grid, International Transmission, New England TOs, NU, NYSEG, and SMUD.

transmission) who might have an interest in investing in a particular project and that the Commission has no basis for discriminating in favor of public power by giving it special investment rights and that doing so will create controversy.

352. Some of these same commenters that support the consortia[185] also support the Commission offering to public power entities the same incentives it is offering to jurisdictional public utilities, including Transcos. For example, AMP-Ohio states that the Commission should encourage arrangements that allow public power entities to obtain direct ownership. Wyoming Infrastructure Authority states that public power participation has demonstrably aided grid expansion projects to increase reliability and efficiency of the transmission grid.

353. Others propose limitations, including limiting incentives to those applicants offering third-party participation in projects.[186] Citizens Energy, for example, states that the Commission should require Transmission Organizations to adopt rules which ensure non-discrimination against merchant transmission. TransCanada proposes a specific process for merchant transmission. FirstEnergy states that public power participation should be permitted only when such entities have an OATT on file with the Commission.

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[185] E.g., AMP-Ohio, Ameren, CAISO, Municipal Commenters, Nevada Companies, Upper Great Plains, Powder River, Wyoming Infrastructure Authority and Snohomish.

[186] E.g., TAPS, TANC, NECOE, Citizens Energy, TDU Systems, and Municipal Commenters..

Still other commenters[187] state public power already enjoys various benefits over investor-owned utilities (e.g., access to low-cost borrowing funds, ability to set own rates, tax advantages) and that the Commission should not further the rate advantages.

3. Commission Determination

354. We agree with comments that public power participation can play an important role in the expansion of the transmission system. We want to encourage public power participation in new transmission projects, but the ratemaking incentives we discuss in the Final Rule are generally not directly available to non-jurisdictional entities such as most public power entities, because they do not file their rates with the Commission. However, to the extent our jurisdiction allows, the Commission will entertain appropriate requests for incentive ratemaking for investment in new transmission projects when public power participates with jurisdictional entities as part of a proposal for incentives for a particular joint project.[188] Encouraging public power participation in such projects is consistent with the goals of section 219 by encouraging a deep pool of participants.

355. We will not specify which incentives might be most appropriate for encouraging participation by public power entities but instead will allow the applicants to make

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[187] E.g., KCPL and EEI.

[188] This is not to say that the Commission would not consider incentive ratemaking treatment for a consortium project that did not include public power participation. Nothing in this rule prevents jurisdictional entities from combining their resources on a project.

proposals that best suit their circumstances. We also clarify that the Commission's approval of an incentive plan proposed by a public utility that also pertains to an entity that is not otherwise jurisdictional under sections 205 and 206 (e.g., public power), does not affect the non-jurisdictional status of the entity.

356. We will not, however, require public power or other joint participation in a transmission project in order for investment in a project to be eligible for incentives. While participation by a diverse group of investors might be the best structure for an individual project, it is inappropriate to mandate a particular joint-structure be used in all cases. However, we clarify that, to the extent allowed under our jurisdiction, a public power entity should have the same opportunity afforded to jurisdictional entities to recover costs related to new transmission investment.

357. We believe a consortium approach that includes public power and other entities for new investment has value and we encourage participation by public power in meeting the transmission infrastructure provisions of section 219. However, we will not require a consortium approach. We believe it is more appropriate for applicants to fashion proposals for new transmission infrastructure projects that are tailored to the specific circumstances and needs of a particular project. In addition, we believe a consortium-led proposal that is the result of an open, collaborative, regional process and that includes a diverse group of participants may face less resistance from parties when a filing is made here, because competing interests will have already been addressed before the proposal is filed with the Commission.

V. Reporting Requirement

A. Background

358. Section 35.35(h) of the proposed rule would require jurisdictional public utilities to report annually to the Commission no later than April 18, 2007, and, in succeeding years, on the date on which FERC Form No. 1 information is due the following data and projections: (subsection i) in dollar terms, actual investment for the most recent calendar year, and planned investments for the next five years; and (subsection ii) for all current and planned investments over the next five years, a project by project listing that specifies for each project the expected completion date, percentage completion as of the date of filing and reasons for delay. A draft Form X was provided in the Appendix.

359. In the NOPR (at P 49), the Commission stated that the purpose of the reporting requirement is to determine the effectiveness of the proposed rules and to provide the Commission with an accurate assessment of the state of the industry with respect to transmission investment.

B. Comments

360. A number of commenters[189] support the proposed Form X reporting requirement. For example, International Transmission states that such reports are important to determine if the investment incentives adopted by the Commission are actually working to elicit investment in transmission that benefits consumers. Some of these commenters

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[189] E.g., International Transmission, NRECA, APPA, National Grid, AEP and TAPS, Siemans, and NEMA.

make a number of recommendations, including the following: define transmission investment for reporting; include separate categories for new generation interconnection versus other types of system upgrades; classify investments by voltage level to distinguish facilities that have little or nothing to do with the interstate transmission grid; exclude small, miscellaneous upgrades; provide instructions that Transmission Facilities in the table "Capital Spending On Electric Transmission Facilities" are defined as transmission assets under the Uniform System of Accounts in accounts 350 through 359; like the report with FERC Form No. 1; provide a list of categories for the "Reasons for Delay" column, such as siting, delayed completion of a new generator; report the consumer benefits of the project (e.g., congestion relief, enhanced reliability); require the posting of the information on RTO, ISO, Transco or public utility websites or OASIS; require that all the reports be aggregated in one report that is made public, thereby providing manufacturers with a better basis to plan for industry needs.

361. Commenters also contend that the report does not go far enough.[190] Some[191] state that such reports should extend to all transmission providers, including those subject to new section 211A of the FPA and government-owned entities. Semantic asserts that the reporting requirements proposal is incomplete and does not adequately secure the

[190] E.g., International Transmission, Northwestern, Siemans, NEMA, and Semantic.

[191] E.g., International Transmission, EEI, Northwestern, and KCP&L.

comprehensive state of the grid information required by the regulators and market participants. Semantics would require that power systems state data must be made available in real-time to identify parallel flows and to avoid under-investment, over-investment or bad investments; that the report should provide for the filing of data that enables the Commission to fulfill its oversight responsibility for RTOs under § 35.34(k)(4) and to promote compliance with § 35.34(k)(1). Semantics further recommends that time of day rate schedules should be reported into a web-accessible national repository. Semantic explains that capital investment in advanced technologies will relieve congestion if this information is made known to technology vendors and entrepreneurial entities.

362. Certain commenters[192] that support the reporting also express concerns. For example, National Grid states the Commission should clarify that the forward-looking projections in Form X, rendered in good faith and upon a reasonable basis, would not subject the reporting transmission owners to claims of fraud, detrimental reliance or other liabilities arising from the fact that actual capital spending may vary from reported projections.[193] Ameren requests that the Commission clarify that the reported information is to be provided for informational purposes only and should not be allowed

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[192] E.g., National Grid, Ameren, PG&E, and Nevada Companies.

[193] See Section 27A of the Securities Act of 1933, as amended; Section 21E of the Securities Exchange Act of 1934, as amended; 15 U.S.C. §§ 77z-2 and 78u-5; 17 CFR § 240.3b-6.

to form the basis of a review by the Commission or other entities regarding the reasonableness or prudence of the amounts reported. PG&E and the Nevada Companies assert that a disclaimer should be added to footnote 1 explaining that much of the information reported here may change over time and may be subject to correction. Trans-Elect asserts that the reporting requirement, alone, should not be allowed to form a basis for a section 206 investigation.

363. Some commenters raise confidentiality concerns.[194] EEI and KCP&L urge that the Commission afford Critical Energy Infrastructure Information (CEII)[195] status to this information since it clearly relates to the production, generation, transmission or distribution of energy, could be useful to a person planning an attack and gives strategic information beyond the location of critical infrastructure. EEI encourages the Commission to perform an evaluation as to the need for confidentiality of selected company information due to the commercially sensitive nature of the information. Similarly, Ameren and TransElect request that the Commission clarify that the required information may be submitted pursuant to the Commission's confidential filing procedures.[196]

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[194] E.g., TransElect, EEI, KCP&L, and Ameren.

[195] They cite Critical Infrastructure Information, Order No. 630, 68 FR 9857 (March 3, 2003), FERC Stats. & Regs. ¶ 31,140 (2003), order on reh'g, Order No. 630-A, 68 FR 46,456 (Aug. 6, 2003), FERC Stats. & Regs. ¶ 31,147 (2003)..

[196] See 18 CFR 388.112.

364. A number of commenters oppose the reporting requirement for a variety of reasons. Several[197] claim that the Commission has not provided adequate justification for the Form X data collection, as required by the Paperwork Reduction Act, given that the Commission already collects information on utility transmission investment and planning in existing FERC Form Nos. 1, 714 and 715 and that the Commission has not demonstrated the need to make the information collection mandatory. Ameren, AEP and PJM TOs state that the requested information duplicates information already being compiled by RTOs in their planning process; and MISO States suggest that the Commission obtain an aggregate report from the RTO. PJM TOs recommend that Form No. 1 requirements be modified prospectively, instead of requiring a new form. EEI is concerned that the Commission, state commissions and the public may inappropriately rely on the information, expecting the plans to be implemented without regard to the regulatory approvals and applicant and market decisions involved. EEI further states that reporting information on planned future facilities can lead to unnecessary opposition that might not occur with a proper public siting process, lead to speculation in land use fees that can harm the applicant's customers.

365. EEI, arguing that the only accurate measure of the effectiveness of the incentives is the number of applications filed for incentives, encourages the Commission to simply

[197] E.g., EEI, Southern, SCE, KCP&L, Nevada Companies, Progress Energy, Mid-American and PG&E.

monitor the number of applications for new transmission facilities, the magnitude of the facilities involved and the incentives sought and thereby obtain the most accurate measure of the effectiveness of the proposed incentives. EEI also encourages the Commission to rely on annual aggregate transmission investment information that EEI has provided to the Commission and can continue collecting for the Commission's benefit. Nevada Companies assert this information should not be required since it is inaccurate and incomplete.

366. Southern, SCE and Ameren propose limitations on the information to be provided as follows: only aggregate information should be required, and project-specific information should not be required since it is extremely burdensome, entails security and confidentiality issues, and is subject to change; if project-level information is required, that it be limited to major transmission projects, i.e., 345 kv and above; and limit project-specific reporting requirements to only projects costing $20 million or more and that are subject to a Transmission Organization's or a regional planning organization's planning and approval process.

C. Commission Determination

367. To ensure that these rules are successfully meeting the objectives of section 219, the Commission needs industry data, projections and related information that detail the level of investment. The rule's purpose is to both provide new investment as well as ensure that customers benefit. Thus, information regarding projected investments as well as information about completed projects will help the Commission to monitor the success

of the ratemaking reforms announced in this rule. Thus, the Commission will adopt the proposed reporting requirement Form X and designate it as the FERC-730. Further, the Commission will make certain modifications to clarify when reports must be filed and what data must be submitted in FERC-730 reports.[198] The information required in FERC-730 is not available from Form Nos. 1, 714 or 715, nor is it available from other federal agencies. For instance, FERC Form No. 1 requires the reporting of historical financial data but does not contain forward looking projections of expected transmission investments.[199] Thus, the information sought is not already readily available and will be required only from public utilities that have been granted incentive rate treatment for specific transmission projects under the provisions of § 35.35.

368. We agree with commenters that, for some utilities, the information requested is similar to information submitted to RTOs. However, the Commission does not receive that information, and the information provided to RTOs may not be identical to the information requested here. Therefore, to ease the administrative burden, those utilities providing information to RTOs can submit the same information to the Commission. We

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[198] FERC-730 filers are reminded that each FERC-730 filing must be accompanied by a Subscription consistent with the requirements of 18 CFR 385.2005(a).

[199] See e.g., FERC Form No. 1 schedule pp. 204-7, "Electric Plant in Service (Accounts 101, 102, 103 and 106)" which requires the reporting of the original cost of electric plant in service and p. 216, "Construction Work in Progress—Electric (Account 107)" which requires the reporting of expenditures for certain construction projects at December 31 of the reporting year.

strongly encourage utilities that submit FERC-730 reports to do so in an electronic format via eFiling.[200] To rely on information collected by EEI, as recommended, would not provide the Commission with the accurate information we need to assess the effectiveness of our regulations under section 219. The Commission would not have available to it the survey instruments or the analysis behind the reported information. Thus, reliance on second-hand gathered survey information for the purposes of rate setting would not provide the independent, factual basis to allow the Commission to make a determination that continuing incentives is appropriate. Likewise, the summary investment information available in existing reports does not provide information on projected investment or reasons for delays in projects, thereby limiting its value for determining the effectiveness of the rules.

369. We do not believe a CEII designation is required for this information since it is expected to only include information on capital spending and a general designation of the project name, without requiring data on facility location. With respect to confidential treatment of FERC-730, as a general matter we do not believe that this type of general planning information involves commercially sensitive information. However, while we will require applicants to provide capital spending projections and other information in their applications, we also recognize that applicants may have legitimate reasons to

[200] The Commission will issue a separate notice on how to submit this data electronically via eFiling.

maintain confidentiality of certain information. For this reason, applicants can request protection of information under § 388.112.

370. With respect to project-level information, this information is needed to determine the status of critical projects and reasons for delay, and will play a role in the Commission's evaluation of continuing incentives. To facilitate this review, we will require that filers specify which projects are currently receiving incentives in the project detail table and that they group together those facilities receiving the same incentive. We will not limit the information to projects above a certain voltage, since lower-voltage projects can have significant impacts on reliability and congestion relief, nor will we limit the information to projects subject to a Transmission Organization's or a regional planning organization's planning and approval process since we are addressing a national problem and complete coverage is therefore necessary. As discussed earlier in this rule, projects eligible for incentives – and hence required to submit data – are not restricted to projects or investments that result from regional planning processes. We agree with SCE that a minimum dollar threshold of $20 million is a reasonable level for reporting of significant projects.

371. We agree with many of the recommendations for modifications to the tables as shown in the revised FERC-730 in the Appendix. We will not require the reporting of consumer benefits of projects. In order for these projects to have received an incentive, the project must have met the requirements of this rule, which includes that it benefit consumers by ensuring reliability and reducing the cost of delivered power by reducing

transmission congestion. We will not require the addition of operating data to the table since the sole purposes of the information collection is to determine the level of capital spending, the status of significant and critical projects and reasons for delay. We will not require a Proposed Operating Date, as recommended by Ameren, since our sole concern with this information is that the planned projects are completed on time; operational start-up issues such as synchronization with the grid and testing introduce additional issues not directly relevant to tracking the progress of investments in new infrastructure.

372. Further, we will not require year-by-year capital spending estimates for the project detail table as recommended by TAPS since the goal of the rule is not to ensure the achievement of annual capital spending targets but rather to ensure the overall project is completed, and if not, the reasons for the delay. We will not require the inclusion of cost allocation or pricing information as recommended by TAPS since that information is beyond the scope of our requirements. We do not see the need for a disclaimer that information is subject to change, since the required information is clearly labeled "projected" and "expected" and therefore assumed to be subject to change. Since this rulemaking applies to public utilities and incentives are being permitted pursuant to sections 219 and 205, which pertain to public utilities, we will not require information from entities that are not jurisdictional under section 205, although such entities are encouraged to voluntarily provide this information. We clarify that the meaning of "On Schedule" in the Project Detail table is the most up-to-date, expected project completion date.

373. We clarify that the reported information is to be provided for informational purposes only, and its purpose is not to establish the prudence of the amounts spent. As we specified earlier in the rule, we expect applicants will propose metrics and provide a nexus between the incentive and the investment, and therefore the information in this report will not be the sole basis for a section 206 investigation. We further clarify that the projections in FERC-730, rendered in good faith and upon a reasonable basis, would not subject the reporting transmission owners to claims of fraud, detrimental reliance or other liabilities arising from the fact that actual capital spending may vary from reported projections.

374. Rather than requiring all public utilities to submit FERC-730, we clarify that only those public utilities that have been granted incentive-based rate treatment for specific transmission projects under the provisions of § 35.35 must file FERC-730 in the manner prescribed in Appendix A. A public utility is subject to the FERC-730 reporting requirement beginning with the year the Commission issues an order in response to a filing made pursuant to section 205 of the Federal Power Act, or in a petition for a declaratory order that precedes a filing pursuant to section 205. The initial FERC-730 filing is due by April 18 of the following calendar year and subsequent filings are due each April 18 thereafter.

375. In addition, we will add a new provision to § 35.35(h) and delegate to the Chief Accountant or the Chief Accountant's designee authority to act on requests for extension

of time to file FERC-730 or to waive the requirements applicable to any FERC-730 filing.

376. Finally, we find the data issues raised by Semantic to be beyond the scope of this rulemaking. While the data requested by Semantic could provide a useful purpose for the operations and management of electric facilities and may have applicability to the Commission's regulations for RTOs, this rulemaking is limited to an evaluation of incentives for investment in electric transmission facilities. Therefore, the reporting requirements of the rulemaking are appropriately limited to data on industry investment.

VI. Other Issues

A. Rate Related Issues

1. Rate Related Issues

377. Commenters also raised other rate issues such as formula rates, rate design, the five-month suspension policy and recovery of other costs. The Commission addresses these issues below.

a. Comments on Formula Rates

378. As an alternative to single-issue ratemaking, certain commenters urge the Commission to require recovery of incentives through various forms of formula rates.[201] Certain MISO TOs state that the Commission should facilitate recovery from wholesale and retail customers including bundled and unbundled retail load through a formula rate

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[201] E.g., APPA, AWEA, KKR, MDU, PG&E, Certain MISO TOs, and TAPS.

for new investments. Certain MISO TOs cite section 219 of the FPA to argue that Congress required the Commission to ensure the recovery of all prudently incurred costs necessary to comply with mandatory reliability requirements and related to transmission infrastructure development.[202]

379. EEI argues that the section 205 filing for a public utility with a formula rate should be limited to including appropriate language in the formula rate allowing the utility to get the incentives and not be the basis to challenge any other aspect of the formula rate.

b. Comments on Rate Design

380. Several commenters urge the Commission to require applicants to seek rolled-in treatment, rather than participant funding, to recover any costs incurred under the rule.[203] Those commenters assert that participant funding is inequitable because it imposes too much of a system burden on limited customers and that participant funding may actually discourage investment.

381. Other commenters support participant funding for projects.[204] They argue that socialization unfairly requires others to pay for facilities that they do not need and may deter new investment. Xcel requests that the Commission provide clear guidance on the

[202] Certain MISO TOs state that all costs of new investment should include the costs of facilities built by the company as well as the costs of facilities allocated to the company through a RTO transmission cost allocation process.

[203] E.g., East Texas, TDU Systems, and TAPS.

[204] E.g., NorthWestern, Progress, Southern Companies, PSEG, and E.ON US.

issue of "rolled in" versus "incremental" pricing. Xcel states that the Commission should allow phased roll-in of transmission facilities as it does for natural gas pipelines because rolled-in pricing would encourage proper siting of generation.

382. EEI states that the Commission should be open to proposals that deviate from the "higher of" policy where justified.

383. Other commenters express support for regional or zonal rates.[205] They argue that regional rates would foster new projects because the rates would match cost recovery to the broad regional benefits obtained and reduce opposition from local consumers and state regulators and litigation.

c. Comments on Five-Month Suspension

384. EEI, SCE and Xcel argue that the Commission's current suspension policy hinders transmission investment because delaying the effective date of rates forces a utility to absorb the costs associated with the new facilities during the suspension period, thereby effectively reducing that utility's return on equity. Additionally, EEI argues that, because any rate increase authorized by the Commission could be made subject to refund, with interest, customers could be made whole even without a five-month suspension. SCE suggests that the Commission should either change the threshold for determining when rates are excessive or use a sliding scale that would impose a longer suspension the larger the excessive revenues.

[205] E.g., TAPS and Upper Great Plains.

d. Other Comments on Rate Design

385. Commenters raised a variety of rate design issues. Energy Capital states that the Commission must modify traditional ratemaking practices to recognize the risks and structures required to fund a single line transmission project. SCE states that an additional disincentive to transmission investment is the imputation of revenues from grandfathered agreements that are greater than the actual revenues under the agreements, thereby reducing the earned return for transmission tariff service. TAPS faults the Commission's policy of excluding EPRI dues from transmission rates because wholesale customers may make their own direct contributions. Trans-Elect requests the Commission to confirm that all financing costs, including prepaid liquidity reserve and working capital costs required by the lender as a condition to financing, are recoverable in rates.

e. Commission Determination

386. We agree with several commenters that formula rates can provide the certainty of recovery that is conducive to large transmission expansion programs.[206] Moreover, formula rates alleviate the need for other relief sought by commenters. For example, public utilities with formula rates will generally be able to flow through increased transmission investment without concern as to the Commission's five-month suspension

[206] We will not rule on PG&E's proposed rate base tracking mechanism here because we do not have an actual proposal with supporting documents before us.

policy with the exception of the suspension period for approval of initial rates. While we continue to encourage public utilities to explore the benefits of filing transmission-related formula rates,[207] we will not require public utilities to use formula rates to recover incentives.

387. We disagree with the interpretation that section 219 requires the Commission to claim jurisdiction over the transmission component of bundled retail load. While MISO TOs are correct that section 219 requires the Commission to ensure the recovery of all costs prudently incurred for section 215 reliability compliance and section 216 national interest corridor investments, we do not believe it is necessary to assert jurisdiction over bundled retail transmission to fulfill this statutory requirement.[208]

388. The rate design issues raised in the comments are beyond the scope of this proceeding.[209] While rate designs can impact infrastructure investment, this rule is

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[207] Allegheny Power System Operating Companies, 111 FERC ¶ 61,308 at P 51 (2005). See also Allegheny Power System Operating Companies, 106 FERC ¶ 61,003 at P 32 (2004) ("The parties may explore whether adopting formula rates for recovery of the costs of both the TOs' existing transmission facilities and new transmission facilities would be best. Specifically, we note that other TOs that we have approved incentive rates for also have formula rates.").

[208] We will not add the term "all" to the regulatory text in 18 CFR 35.35(f) and (g) as recommended by Certain MISO TOs. The text in those sections reflects the language in section 219 of the FPA and therefore meets the Commission's compliance requirements.

[209] We will not retain 18 CFR 35.34(e) in the new regulations as requested by MISO States. However, the new regulations allow RTOs to propose alternative incentives in 18 CFR 35.35(d)(1)(iii) and under these new regulations, RTOs may

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limited to addressing incentive treatments that foster infrastructure investment. Interested parties may raise issues associated with rate design policies in the associated section 205 filings in which applicants are seeking rate recovery of transmission incentives.

389. We will not revise our five-month suspension policy in this proceeding. To the extent that public utilities are concerned that the Commission's suspension policy unnecessarily delays recovery of prudent costs, there are alternative means to ensure such recovery. As mentioned previously, formula rates enhance cost recovery certainty. Further, public utilities that are concerned that a particular rate increase may be deemed "excessive" under our suspension policy may use our pre-filing process for discussing those concerns.

390. We will not make the determination on Energy Capital's proposal that the Commission modify its traditional ratemaking practices to recognize unique aspects of non-traditional transmission owners because the issues raised are novel and we would be better informed with an actual proposal before us. Regarding SCE's concern about imputing the transmission revenues under grandfathered agreements using the OATT rate, this issue is beyond the scope of this proceeding.

391. We shall deny TAPS proposal to reconsider our policy on recovery of EPRI research and development costs when the unbundled retail load takes service under the

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propose the incremental pricing provisions previously included in 18 CFR 35.34(e).

same transmission rate as wholesale customers.[210] That is beyond the scope of this proceeding.

392. The Commission will remain flexible with respect to rate treatments proposals that applicants or interested parties can demonstrate to be just and reasonable.

393. We will deny the request to confirm in this proceeding that prepaid liquidity reserve and working capital costs required by project lenders as a condition to financing are recoverable. Those issues were the subject of an Administrative Law Judge's Initial Decision in Docket No. ER05-17-002 and are pending Commission review. Those issues are better addressed in that proceeding because that proceeding has a complete litigated record.

394. We also find that EEI's request that the Commission use this rule to revisit "and" pricing to be beyond the scope of this rule.

B. Section 35.34

1. The Proposal to Eliminate Section 35.34(e)

a. Background

395. The NOPR proposed that applicants for incentive ratemaking treatment under section 35.35 would not be required to support their applications with cost-benefit

[210] The Commission has explained that, when the basis for calculating the amount of the voluntary contribution to EPRI for research and development is based on the amount of retail sales, recovery from wholesale customers is unreasonable. See Public Service Company of New Mexico, Opinion 133, 17 FERC ¶ 61,123 at 61,249 (1981), order on reh'g, Opinion No. 133-A, 18 FERC ¶ 61,036 (1982).

analyses. The NOPR also proposed to eliminate § 35.34(e), which requires cost-benefit analyses by RTO applicants in order to avoid potential conflict between or overlap of the pre-existing regulations and the new § 35.35.

b. Comments

396. Several comments specifically addressed the NOPR's proposal to eliminate § 35.34(e). TDU Systems do not oppose elimination of § 35.34(e), so long as the consumer protections embodied in that section are incorporated into a new rule adopted to replace it. TDU Systems argues that adoption of the conditions and criteria it recommends (i.e., public power participation in planning, financing and construction, and rolled-in rate treatment for expansions of network facilities) would ensure that these protections remain in place. TAPS, APPA and Industrial Consumers support retention of the cost-benefit provision for reasons given in their comments on the cost-benefit issue.

397. NRECA supports the Commission's proposal. Public utilities have had the opportunity for five years now to form RTOs and obtain transmission rate incentives for RTO membership. In light of the fact that it is yet to be demonstrated that the benefits of RTOs outweigh their cost, elimination of this provision is appropriate.

398. MISO supports the elimination of § 35.34(e), because it will be superfluous and unnecessary if the NOPR is adopted. Moreover, MISO points out that the authorization for RTOs to include innovative rate treatments in their rates found in § 35.34(e) expired after January 1, 2005, with respect to transmission rate moratoriums and rates of return that do not vary with capital structure.

399. Ameren Services does not oppose the Commission's proposal to remove existing section 18 C.F.R. § 35.34(e) from its regulation. This is consistent with the mandate of new FPA section 219 to provide incentives for qualifying entities. Ameren Services contends that removal of § 35.34(e) will avoid confusion that could arise from potential conflicts between innovative rate treatments available under existing § 35.34(e) and the additional incentives proposed to be adopted in new § 35.35.

400. MISO States generally support the elimination of § 35.34(e). However, MISO States point out that § 35.34(e) appears to contain a provision that permits RTOs to apply for incremental pricing for new transmission facilities in association with an embedded-cost access fee for existing transmission facilities. Such a provision does not appear to be encompassed in the language of the Commission's proposed new § 35.35 rule. MISO States believe that such a provision could prove useful in certain circumstances and urges the Commission not to drop this provision in the transition process of deleting the elements in § 35.34(e) and replacing them with the new elements in § 35.35.

401. NorthWestern opposes preferential treatment based on corporate structure. It argues that if the Commission does remove § 35.34(e) as proposed, it should make certain that its resulting policies provide the appropriate non-preferential treatment.

c. Commission Determination

402. Comments opposing the elimination of the cost-benefit analysis requirement are addressed above in our determination to affirm the NOPR on the cost-benefit issue.

403. MISO States expresses concern that the proposed new § 35.35 does not appear to

encompass the provision in pre-existing § 35.34(e)(v) allowing RTOs to apply for incremental pricing for new transmission facilities in association with an embedded-cost access fee for existing transmission facilities. The deletion of § 35.34(e) is intended to eliminate potentially conflicting or overlapping regulations concerning requests for incentive rate treatment. Thus, for example, the deletion of § 35.34(e) eliminates potential confusion over whether a proposal would be an "innovative" rate treatment (and require a cost-benefit analysis) under the pre-existing rules or be an incentive rate treatment requirement (with no cost-benefit analysis) under the new rules.

404. In Section IV.D. of this preamble in our determination segment, we find that we do not have a sufficient basis to adopt rules for PBR in this rule. Notwithstanding that determination not to enumerate PBR in the list of incentive rate treatments, we also state that we remain open to consider PBR proposals as an incentive rate treatment pursuant to section 219. Given that determination, and to avoid potential conflict or overlap with the rules adopted herein, we believe that removal of the pre-existing PBR provisions – §§ 35.34(e)(2)(v) and 35.34(e)(3) – is appropriate.

405. We address NorthWestern's comment that the Commission should not favor any particular corporate structure in the discussion of the Transco incentives, supra Section IV.

VII. Information Collection Statement

406. The Office of Management and Budget (OMB) regulations require approval of

certain information collection requirements imposed by agency rules.[211] The Commission is submitting these reporting requirements to OMB for its review and approval under section 3507(d) of the Paperwork Reduction Act.[212] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. Interested persons may obtain information on the reporting requirements by contacting: Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426 [Attention: Michael Miller, Office of the Executive Director, Phone: (202) 502-8415, fax: (202) 273-0873, e-mail: michael.miller@ferc.gov].

407. Public Reporting Burden: The Commission did not receive specific comments concerning its burden estimates and uses the same estimate here. Comments on the proposed reporting requirement (proposed in the NOPR as Form X) are addressed above in Section V, Reporting Requirements, where we adopt the FERC-730 information collection requirement. The comments received and our adoption of FERC-730 do not lead us to revise the NOPR's estimates of the public reporting burden.

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[211] 5 CFR 1320.13 (2005).

[212] 44 U.S.C. 3507(d) (2000).

Data Collection	No. of Respondents	No. of Responses	Hours Per Response	Total Annual Hours
FERC-516				
Transcos	30	1	296	8,880
Traditional Public Utilities	200	1	181	36,200
FERC-730	200	1	30	6,000
Totals	230	1	222	51,080

Total Annual hours for Collection: (Reporting + recordkeeping, (if appropriate)= 51,080 hours.

Information Collection Costs: The Commission sought comments about the time and corresponding costs needed to comply with these requirements. No comments were received. Costs for FERC-516 and FERC-730 = $6,129,600 (51,080 hours at $120 an hour). (The hourly rate was determined by taking the median annual salary from Bureau of Labor Statistics, Department of Labor Occupational Outlook Handbook. The figures reported by BLS are for 2002 and added to them was an inflation factor of 4.73 percent for the period January 2003 through December 2004.)

Title: FERC-516 "Electric Rate Schedule Filings", FERC-730 "Report of Transmission Investment Activity"

Action: Proposed Collections

OMB Control No: 1902-0096; and to be determined

Respondents: Business or other for profit

Frequency of Responses: On occasion for applicants and annually for transmission investment report.

Necessity of the Information: The Final Rule amends the Commission's regulations to implement the statutory provisions of section 1241 of EPAct 2005. The Act directs the Commission to establish incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities in order to benefit consumers by ensuring reliability and reducing the cost of delivered power by relieving transmission congestion. This mandate addresses an identified need to encourage construction of transmission infrastructure and encourage investment. Sufficient supplies of energy and a reliable way to transport those supplies are necessary to assure reliable energy availability and to enable competitive markets. Without sufficient delivery infrastructure, some suppliers will not be able to enter the market, customer choices will be limited, and prices may be needlessly higher or volatile. The implementation of incentive and performance-based rate treatments supports the Commission's mandate to support investments in transmission capacity to reduce the cost of delivered power by reducing congestion.

408. Entities seeking incentives to build new transmission facilities must file under Part 35 of the Commission's regulations, an application describing how the entity will bring benefits to the grid. The information provided for under Part 35 is identified as FERC-516. The information for actual and planned investments as proposed in an annual report is identified as FERC-730 and the information is provided for under § 35.35(h) of the Commission's regulations.

409. Comments on the final rule may also be sent to the Office of Management and Budget. For information on the requirements, submitting comments on the collection of information and the associated burden estimates including suggestions for reducing this burden, please send your comments to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426 (Attention: Michael Miller, Office of the Executive Director, (202-502-8415) or send comment to the Office of Management and Budget (Attention: Desk Officer for the Federal Energy Regulatory Commission, fax: 202-395-7285, e-mail: oria_submission@omb.eop.gov., and please reference this rulemaking docket no. in your submission.

VIII. Environmental Statement

410. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[213] The Commission has categorically excluded certain

[213] Regulations Implementing the National Environmental Policy Act, Order No.
(continued)

actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[214] Thus, we affirm the finding we made in the NOPR that this Final Rule is procedural in nature and therefore falls under this exception; consequently, no environmental consideration would be necessary.

IX. Regulatory Flexibility Act Certification

411. The Regulatory Flexibility Act (RFA)[215] requires that a rulemaking contain either a description and analysis of the effect that the Final Rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities. However, the RFA does not define “significant” or “substantial” instead leaving it up to any agency to determine the impacts of its regulations on small entities. The Final Rule will not have a significant adverse impact on a substantial number of small entities. The Final Rule applies only to entities that own, control, or operate facilities for transmitting electric energy in interstate commerce and not to electric utilities per se. Small entities that believe this Final Rule will have a significant impact on them may apply to the Commission for waivers.

486, 52 FR 47897 (1987), FERC Stats. & Regs. ¶ 30,783 (1987).

[214] 18 CFR 380.4(a)(2)(ii).

[215] 5 U.S.C. 601-612 (2000).

X. Document Availability

412. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington, D.C. 20426.

413. From the Commission's Home Page on the Internet, this information is available in the eLibrary. The full text of this document is available on eLibrary both in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

414. User assistance is available for eLibrary and the Commission's website during normal business hours. For assistance, please contact Online Support at 1-866-208-3676 (toll free) or 202-502-6652 (e-mail at FERCOnlineSupport@FERC.gov), or the Public Reference Room at 202-502-8371, TTY 202-502-8659 (e-mail at public.referenceroom@ferc.gov).

XI. Effective Date and Congressional Notification

415. This Final Rule will take effect [insert date 60 days after date of publication in the Federal Register]. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of the Office of

Management and Budget, that this rule is not a major rule within the meaning of section 251 of the Small B**u**siness Regulatory Enforcement Fairness Act of 1996.[216] The Commission will submit the Final Rule to both houses of Congress and the Government Accountability Office.[217]

List of subjects in 18 CFR Part 35

Electric power rates
Electric utilities
Reporting and recordkeeping requirements

By the Commission.

Magalie R. Salas,
Secretary.

[216] 5 U.S.C. 804(2) (2000).

[217] 5 U.S.C. 801(a)(1)(A) (2000).

In consideration of the foregoing, the Commission amends part 35 of Chapter I, Title 18, Code of Federal Regulations, as follows:

PART 35 – FILING OF RATE SCHEDULES AND TARIFFS

1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 7101-7352.

Subpart F – Procedures and Requirements Regarding Regional Transmission Organizations

§ 35.34 [Amended]

2. In § 35.34, remove and reserve paragraph (e).

3. A new subpart G is added to read as follows:

Subpart G – Transmission Infrastructure Investment Provisions

§ 35.35 Transmission infrastructure investment.

(a) Purpose. This section establishes rules for incentive-based (including performance-based) rate treatments for transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.

(b) Definitions.

(1) Transco means a stand-alone transmission company that has been approved by the Commission and that sells transmission services at wholesale and/or on an unbundled retail basis, regardless of whether it is affiliated with another public utility.

(2) Transmission Organization means a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities.

(c) General rule. All rates approved under the rules of this section, including any revisions to the rules, are subject to the filing requirements of sections 205 and 206 of the Federal Power Act and to the substantive requirements of sections 205 and 206 of the Federal Power Act that all rates, charges, terms and conditions be just and reasonable and not unduly discriminatory or preferential.

(d) Incentive-based rate treatments for transmission infrastructure investment. The Commission will authorize any incentive-based rate treatment, as discussed in paragraph (d), for transmission infrastructure investment, provided that the proposed incentive-based rate treatment is just and reasonable and not unduly discriminatory or preferential. A public utility's request for one or more incentive-based rate treatments, to be made in a filing pursuant to section 205 of the Federal Power Act, or in a petition for a declaratory order that precedes a filing pursuant to section 205, must include a detailed explanation of how the proposed rate treatment complies with the requirements of section 219 of the Federal Power Act and a demonstration that the proposed rate treatment is just, reasonable, and not unduly discriminatory or preferential. The applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219, that there is a nexus between the incentive sought and the investment being made, and that resulting rates are just and reasonable. For purposes of paragraph (d), incentive-based rate treatment means any of the following:

(1) The Commission will authorize the following incentive-based rate treatments for investment by public utilities, including Transcos, in new transmission capacity that reduces the cost of delivered power by reducing transmission congestion or ensures reliability, and is otherwise just, reasonable and not unduly discriminatory or preferential, as demonstrated in an application to the Commission:

(i) A rate of return on equity sufficient to attract new investment in transmission facilities;

(ii) 100 percent of prudently incurred Construction Work in Progress (CWIP) in rate base;

(iii) Recovery of prudently incurred pre-commercial operations costs;

(iv) Hypothetical capital structure;

(v) Accelerated depreciation used for rate recovery;

(vi) Recovery of 100 percent of prudently incurred costs of transmission facilities that are cancelled or abandoned due to factors beyond the control of the public utility;

(vii) Deferred cost recovery; and

(viii) Any other incentives approved by the Commission, pursuant to the requirements of this paragraph, that are determined to be just and reasonable and not unduly discriminatory or preferential.

(2) In addition to the incentives in § 35.35(d)(1), the Commission will authorize the following incentive-based rate treatments for Transcos, provided that the proposed incentive-based rate treatment is just and reasonable and not unduly discriminatory or preferential:

(i) A return on equity that both encourages Transco formation and is sufficient to attract investment; and

(ii) An adjustment to the book value of transmission assets being sold to a Transco to remove the disincentive associated with the impact of accelerated depreciation on federal capital gains tax liabilities.

(e) Incentives for joining a Transmission Organization. The Commission will authorize an incentive-based rate treatment, as discussed in paragraph (e), for public utilities that join a Transmission Organization, if the applicant demonstrates that the proposed incentive-based rate treatment is just and reasonable and not unduly discriminatory or preferential. Applicants for the incentive-based rate treatment must make a filing with the Commission under section 205 of the Federal Power Act. For purposes of paragraph (e), an incentive-based rate treatment means a return on equity that is higher than the return on equity the Commission might otherwise allow if the public utility did not join a Transmission Organization. The Commission will also permit transmitting utilities or electric utilities that join a Transmission Organization the ability to recover prudently incurred costs associated with joining the Transmission Organization, either through transmission rates charged by transmitting utilities or electric utilities or through transmission rates charged by the Transmission Organization that provides services to such utilities.

(f) Approval of prudently-incurred costs. The Commission will approve recovery of prudently-incurred costs necessary to comply with the mandatory reliability standards pursuant to section 215 of the Federal Power Act, provided that the proposed rates are just and reasonable and not unduly discriminatory or preferential.

(g) Approval of prudently incurred costs related to transmission infrastructure development. The Commission will approve recovery of prudently-incurred costs related to transmission infrastructure development pursuant to section 216 of the Federal Power Act, provided that the proposed rates are just and reasonable and not unduly discriminatory or preferential.

(h) FERC-730, Report of transmission investment activity. Public utilities that have been granted incentive rate treatment for specific transmission projects must file FERC-730 on an annual basis beginning with the calendar year incentive rate treatment is granted by the Commission. Such filings are due by April 18 of the following calendar year and are due April 18 each year thereafter. The following information must be filed:

(1) In dollar terms, actual transmission investment for the most recent calendar year, and projected, incremental investments for the next five calendar years;

(2) For all current and projected investments over the next five calendar years, a project by project listing that specifies for each project the most up-to-date, expected completion date, percentage completion as of the date of filing, and reasons for delays. Exclude from this listing projects with projected costs less than $20 million; and

(3) For good cause shown, the Commission may extend the time within which any FERC-730 filing is to be filed or waive the requirements applicable to any such filing. The authority to act on motions for extensions of time to file FERC-730 or to waive the requirements applicable to any FERC-730 filing, including granting or denying such motions, in whole or in part, is delegated to the Chief Accountant or the Chief Accountant's designee.

(i) Rebuttable presumption. The Commission will apply a rebuttable presumption that an applicant has met the requirements of section 219 for:

(i) A transmission project that results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission;

(ii) A project that has received construction approval from an appropriate state commission or state siting authority; or

(iii) A proposed project that is located in a National Interest Electric Transmission Corridor pursuant to section 216 of the Federal Power Act.

Note: The following appendices will not be published in the Code of Federal Regulations.

APPENDIX A

FERC-730, Report of Transmission Investment Activity

Company Name: ____

Table 1: Actual and Projected Electric Transmission Capital Spending

Capital Spending On Electric Transmission Facilities 1/ ($ Thousands)	Actual at December 31,	Projected Investment (Incremental Investment by Year for Each of the Succeeding Five Calendar Years)				
	20__	20__	20__	20__	20__	20__

1/ Transmission facilities are defined to be transmission assets as specified in the Uniform System of Accounts in account numbers 350 through 359 (see, 18 CFR Part 101).

Table 2: Project Detail 1/

Project Description 2/	Project Type 3/	Expected Project Completion Date (month/year)	Completion Status 4/	Is Project On Schedule? (Y/N)	If Project Not On Schedule, Indicate Reasons For Delay 5/

1/ Respondents must list all projects included in the actual and projected electric transmission capital spending table, excluding those projects with projected costs less than $20 million.

2/ Project description should include voltage level.

3/ Project types are New Build, Upgrade of Existing, Refurbishment/Replacement, or Generator Direct Connection.

4/ Completion status designations are Complete, Under Construction, Pre-Engineering, Planned, Proposed, and Conceptual.

5/ Reasons for delay designations are Siting, Permitting, Construction, Delayed Completion of New Generator, or Other (specify).

APPENDIX B

Commenters on the NOPR

<u>Public Utilities and Trade Associations</u>

Ameren Service Company (Ameren)

American Electric Power System Corporation (AEP)

American Transmission Companies (American Transmission)

WestConnect Public Utilities (WestConnect)

Baltimore Gas and Electric Company (BG&E)

California Independent System Operator Corporation (California ISO)

Certain Midwest ISO Transmission Owners (Certain MISO TOs)

Citizens Energy Corporation (Citizens Energy)

Consumers Energy Company (Consumers Energy)

DTE Energy Company (DTE Energy)

Duquesne Light Company (Duquesne)

E.ON U.S. LLC (E.ON US)

Edison Electric Institute (EEI)

Electric Power Supply Association (EPSA)

FirstEnergy Service Company (FirstEnergy)

Gridwise Alliance (Gridwise)

International Transmission Company (International Transmission)

ISO New England (ISO-NE)

Kansas City Power & Light Company (KCPL)

MidAmerican Energy Company (MidAmerican)

Midwest Independent Transmission System Operator, Inc. (Midwest ISO)

Montana-Dakota Utilities (Montana-Dakota)

National Grid USA (National Grid)

Nevada Power Company and Sierra Pacific Power Company (Nevada Companies)

New England Transmission Owners (New England TOs)

New York Independent System Operator, Inc. (New York ISO)

New York Electric & Gas Corporation and Rochester Gas & Electric Corporation (NYSEG and RGE)

Northeast Utilities (NU)

NorthWestern Corporation (NorthWestern)

NSTAR Electric & Gas Corporation (NSTAR)

Pacific Gas and Electric Company (PG&E)

PacifiCorp

Pepco Holdings, Inc., et al. (Pepco)

PJM Interconnection, LLC (PJM)

PJM Transmission Owners (PJM TOs)

Progress Energy, Inc. (Progress Energy)

PSEG Companies (PSEG)

Public Service Company of New Mexico and Texas-New Mexico Power Company (PNM and TNMP)

San Diego Gas & Electric Company (SDG&E)

Southern California Edison Company (SCE)

Southern Company Services, Inc. (Southern Companies)

Trans-Elect, Inc. (Trans-Elect)

United Illuminating Company (United Illuminating)

WPC Companies (WPS)

Xcel Energy Services, Inc. (Xcel)

Public Power Entities and Associations

American Municipal Power-Ohio, Inc. (AMP-Ohio)

American Public Power Association (APPA)

Bonneville Power Administration (Bonneville)

California Department of Water Resources State Water Project (CADWR)

CAPX Utilities (CAPX Utilities)

Community Power Alliance

Dairyland Power Cooperative (Dairyland)

East Texas Cooperatives (East Texas)

Hamilton, Ohio, et al. (Municipal Commenters)

Imperial Irrigation District (Imperial)

Los Angeles Department of Water and Power (LADWP)

National Rural Electric Cooperative Association (NRECA)

New England Consumer-Owned Entities (NECOE)

New York Association of Public Power (NY Association)

Public Power Council (PPC)

Public Utility District No. 1 of Snohomish County, Washington (Snohomish)

Sacramento Municipal Utility District (SMUD)

Transmission Access Policy Study Group (TAPS)

Transmission Agency of Northern California (TANC)

Transmission Dependent Utility Systems (TDU Systems)

Upper Great Plains Transmission Coalition (Upper Great Plains)

Wyoming Infrastructure Authority

<u>State Commissions and Other State Entities</u>

California Electricity Oversight Board (California Oversight Board)

Public Utilities Commission of the State of California (California Commission)

Committee on Regional Electric Power Cooperation (CREPC)

Connecticut Attorney General (Connecticut AG)

Connecticut Department of Public Utility Control (Connecticut DPUC)

Delaware Public Service Commission (Delaware Commission)

Kentucky Public Service Commission (Kentucky Commission)

Long Island Power Authority and Long Island Lighting Company (LIPA)

Maryland Public Service Commission (Maryland Commission)

Missouri Public Service Commission (Missouri Commission)

National Association of Regulatory Commissioners (NARUC)

National Association of State Regulatory Consumer Advocates (NASUCA)

New England Conference of Public Utility Commissioners (NECPUC)

New Jersey Board of Public Utilities (New Jersey Board)

New Mexico Attorney General (New Mexico AG)

New York Public Service Commission (New York Commission)

North Dakota Industrial Commission (North Dakota Commission)

Oklahoma Corporation Commission (Oklahoma Commission)

Organization of MISO States (MISO States or OMS)

Pennsylvania Public Utility Commission (Pennsylvania Commission)

Wyoming Office of Consumer Advocate (Wyoming Consumer Advocate)

Others

American Superconductor Corporation (American Superconductor)

American Wind Energy Association (AWEA)

Babcock & Brown, L.P. (Babcock & Brown)

Coalition for the Commercial Application of Superconductors (CCAS)

Consumer Energy Policy of America (CECA)

Electric Power Research Institute (EPRI)

Energy Capital

Energy Financing, Inc. (Energy Financing)

Industrial Consumers [ELCON, et al.] (Industrial Consumers)

JH2 Risk Advisors (JH2)

Kohlberg Kravis Roberts & Co. (KKR)

National Electrical Manufacturers Association (NEMA)

Norton Energy Storage (Norton)

Powder River Energy Corporation (Powder River)

Sabey Corporation (Sabey)

Semantic Applications, Inc. (Semantic)

Siemens Power Transmission & Distribution (Siemens)

Steel Manufacturers Association (Steel Manufacturers)

TransCanada Pipelines Limited (TransCanada)

UTC Power

Vectren Corporation (Vectren)

<u>Reply and Supplemental Comments</u>

EEI

International Transmission

KKR

National Grid

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

(Docket No. RM06-4-001; Order No. 679-A)

Promoting Transmission Investment through Pricing Reform

(Issued December 22, 2006)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule; Order on Rehearing.

SUMMARY: In this order on rehearing, the Federal Energy Regulatory Commission (Commission) reaffirms its determinations in part and grants rehearing in part of Promoting Transmission Investment through Pricing Reform, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006). Order No. 679 amended Commission regulations to establish incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.

EFFECTIVE DATE: This order on rehearing will be effective on [Insert date 30 days after the publication in **Federal Register**].

FOR FURTHER INFORMATION CONTACT:

Jeffrey Hitchings (Technical Information)
Office of Energy Markets and Reliability

Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
202-502-6042

Andre Goodson (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
202-502-8560

Tina Ham (Legal Information)
Office of the General Counsel
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
202-502-6224

SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Promoting Transmission Investment through Pricing Reform — Docket No. RM06-4-001

ORDER NO. 679-A

ORDER ON REHEARING

(Issued December 22, 2006)

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APPENDIX

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Promoting Transmission Investment through Pricing Pricing Reform — Docket No. RM06-4-001

ORDER NO. 679-A

ORDER ON REHEARING

(Issued December 22, 2006)

I. Introduction

1. On July 20, 2006, the Commission issued a Final Rule in this proceeding.[1] In the Final Rule, the Commission amended its regulations to establish incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities. These incentives are intended to benefit consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. We took this action pursuant to section 1241 of the Energy

[1] Promoting Transmission Investment through Pricing Reform, Order No. 679, 71 FR 43294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) (Order No. 679 or Final Rule).

Policy Act of 2005 (EPAct 2005),[2] which added a new section 219 to the Federal Power Act (FPA). The Final Rule identified ratemaking treatments available under section 219. The Final Rule did not grant incentives to any particular entity, but rather required each applicant to demonstrate that it could meet the requirements of section 219 and the Final Rule.

2. Many entities sought rehearing of the Final Rule.[3] The petitioners representing consumer interests argue that the Final Rule was too permissive in offering rate incentives. We have carefully reviewed these petitions and grant them in part in this order.

3. In doing so, we do not, however, depart from a fundamental commitment to provide incentives to support the development of transmission infrastructure. Section 219 was enacted because of a long decline in transmission investment that is threatening reliability and causing billions of dollars in congestion costs. To reverse this historical trend, section 219 directed the Commission to "establish, by rule, incentive-based (including performance-based) rate treatments" that: “promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the

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[2] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 315 and 1283 (2005).

[3] The parties who filed the requests for rehearing and/or clarification are listed in Appendix A.

transmission of electric energy in interstate commerce, regardless of the ownership of the facilities; provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies); encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities; and allow recovery of – (A) all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215 and (B) all prudently incurred costs related to transmission infrastructure development pursuant to section 216."[4] The Final Rule fulfilled that command by providing a range of rate treatments that remove impediments to new investment or otherwise attract that investment.

4. This order retains those rate treatments, but modifies the way in which they are applied in three principal respects to address the concerns of petitioners.

5. First, NARUC argues that we erred in rebuttably presuming that certain review processes (e.g., state siting approvals and regional planning processes) satisfy section 219's requirement that a transmission project ensure reliability or reduce congestion. NARUC contends that these review processes do not, in all cases, establish the need for a particular facility. We grant rehearing in part on this issue. The Commission created the rebuttable presumption because we do not wish to duplicate the work of state siting authorities, regional planning processes, or the U.S. Department of Energy (DOE) under

[4] 16 U.S.C.A. 824s(a), (b)(1) (West Supp. 2006).

EPAct section 1221. However, we agree with NARUC to the extent that, if review processes do not include a determination of whether a project ensures reliability or reduces congestion, no rebuttable presumption should exist for that project. We will therefore require that each applicant explain whether any process being relied upon for a rebuttable presumption includes a determination that the project is necessary to ensure reliability or reduce congestion. Furthermore, we clarify that this rebuttable presumption applies only to whether the project reduces congestion or encourages reliability, not the additional requirements of the Final Rule. As discussed more fully elsewhere in this order, we also grant rehearing with respect to the Final Rule's rebuttable presumption concerning a National Interest Electric Transmission Corridor (NIETC) designation.

6. Second, the Final Rule required that each applicant demonstrate a nexus between the incentive being sought and the investment being made. Several petitioners argue that the nexus test is not sufficiently rigorous to protect consumers. We grant rehearing in part on this issue. The Final Rule stated that the nexus test is to be applied separately to each incentive, rather than to the package of incentives as a whole. We agree that this approach fails to protect consumers where an applicant both seeks incentives that reduce the risk of the project <u>and</u> seeks an enhanced rate of return on equity (ROE) for increased risk. We will therefore grant in part rehearing and require applicants to demonstrate that the <u>total</u> package of incentives is tailored to address the demonstrable risks or challenges

faced by the applicant in undertaking the project.[5] If some of the incentives in the package reduce the risks of the project, that fact will be taken into account in any request for an enhanced ROE.

7. Third, several petitioners argue that the Final Rule erred in its treatment of incentive returns on equity. Specifically, they fear the Commission will routinely grant ROEs at the top end of the zone of reasonableness. Although the Commission has broad discretion to establish returns on equity anywhere within the zone of reasonableness, we must be careful in the manner we exercise this discretion. The Commission clarifies below that we do not intend to grant incentive returns "routinely" or that, when granted, they will always be at the "top" of the zone of reasonableness. Rather, each applicant will, first, be required to justify a higher ROE under the required nexus test and, second, to justify where in the zone of reasonableness that return should lie. Furthermore, we recognize that some investors may desire up-front certainty regarding ROE before they invest in a particular project. Because our traditional ratemaking practice typically determines ROE in a hearing only after an investment is made and a facility is constructed, it does not provide such up-front certainty. We therefore clarify that we will entertain requests for a specific ROE determination in a petition for declaratory order.

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[5] The Commission will apply a rule of reason with respect to what is sufficient to meet the requirement of “demonstrable” risk or challenge. An applicant may provide specific evidence of a risk or challenge or a supported explanation of why it faces a particular risk or challenge.

8. In this order, the Commission denies in part and grants in part the requests for rehearing and/or clarification.

II. **Background**

9. Section 1241 of EPAct 2005 directed the Commission to establish, no later than one year after enactment of section 219, by rule, incentive-based (including performance-based) rate treatments for the transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion.[6] To that end, the Commission issued a Notice of Proposed Rulemaking (NOPR)[7] on November 18, 2005 seeking comment on the Commission's proposal to comply with section 219. In the NOPR, the Commission stated that the purpose of this rulemaking is to promote greater capital investment in new transmission capacity, recognizing that the need for capital investment in energy infrastructure is a national problem that requires a national solution. Inadequate transmission infrastructure results in transmission congestion that impedes competitive wholesale markets and impairs the reliability of the electric grid.[8]

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[6] 16 U.S.C.A. 824s(a) (West Supp. 2006).

[7] Promoting Transmission Investment Through Pricing Reform, Notice of Proposed Rulemaking, 70 Fed. Reg. 71409 (Nov. 29, 2005), FERC Stats. & Regs., Proposed Regs. ¶ 32,593 (2005).

[8] Id. P 2.

10. After considering the comments on the NOPR, the Commission issued its Final Rule on transmission investment incentives to address the need for transmission capacity. In the Final Rule, the Commission provided incentives for transmission infrastructure investment that will help ensure the reliability of the bulk power transmission system in the United States and reduce the cost of delivered power to customers by reducing transmission congestion. The Final Rule identified specific incentives that the Commission will allow when justified in the context of individual declaratory orders or section 205 filings by public utilities under the FPA.[9] The Commission stated that the Final Rule does not grant incentives to any public utility but instead permits an applicant to tailor its proposed incentives to the type of transmission investments being made and to demonstrate that its proposal meets the requirements of section 219. Further, incentives will be permitted only if the incentive package as a whole results in a just and reasonable rate.[10]

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[9] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 1.

[10] Id. P 2. Also, in the Final Rule, the Commission agreed with comments that new transmission technologies will be adopted when they are cost effective. The Commission determined that incentives will be considered for advanced technologies through the same evaluation process as other technologies. The Commission declined to make generic determinations regarding the applicability of incentives to particular technologies. Rather, the Final Rule determined that to the extent that applicants seek additional incentives for advanced technologies, the Commission will consider the propriety of such incentives on a case-by-case basis. Id. P 288-93, 298-99. The Final Rule required applicants for incentive rate treatment to provide a technology statement that describes what advanced technologies have been considered and, if those technologies are not to be deployed or have not been deployed, an explanation of why

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III. Discussion

A. Procedural Matters

11. In response to the Final Rule, a number of parties submitted timely requests for rehearing and/or clarification. On August 22, 2006, the Attorney General of the State of Connecticut (Connecticut AG) filed a request for rehearing out of time, seeking to support and join in all aspects the New England Commissions' request for rehearing. On September 21, 2006, International Transmission Company (International Transmission) filed an answer to SoCal Edison's request for rehearing.

12. Pursuant to Rule 713(b) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.713(b) (2006), we will deny the request for rehearing of the Connecticut Attorney General because it was filed more than 30 days after issuance of the Final Rule.[11] Rule 713(d) of the Commission's Rules of Practice and Procedure[12] prohibits an answer to a request for rehearing. Therefore, we deny International Transmission's answer to SoCal Edison's request for rehearing.

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they were not deployed. Id. P 302. No party sought rehearing concerning the Final Rule's determinations regarding advanced technologies.

[11] We note, however, that the Connecticut Attorney General supports New England Commissions' request for rehearing, which we address in this order.

[12] 18 CFR 385.713(d) (2006).

B. <u>Statutory Arguments</u>

1. <u>Rehearing Requests</u>

13. APPA/NRECA argue that the Commission misinterpreted section 219 as requiring greater flexibility in ratemaking practices. According to APPA/NRECA, "incentives" are not necessary to attract capital because, under existing Supreme Court precedent, "a public utility's rate of return should also be sufficient to attract investment in new transmission facilities."[13] APPA/NRECA therefore conclude that section 219 merely "codified the longstanding Commission and judicial interpretations of FPA section 205's requirement that rates be just and reasonable."[14]

2. <u>Commission Determination</u>

14. We agree with APPA/NRECA that section 219 did not modify the requirement that rates be just and reasonable under section 205, but disagree that it did no more than restate that longstanding principle. Section 219 makes very clear that the Commission "<u>shall</u> establish, by rule, incentive-based (including performance-based) rate treatments" and that these rate treatments "<u>shall</u> . . . promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of the ownership of the

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[13] APPA/NRECA at 12.

[14] <u>Id</u>. at 12-13.

facilities; provide a return on equity that attracts new investment in transmission facilities (including related transmission technologies); encourage deployment of transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities and improve the operation of the facilities and allow recovery of – (A) all prudently incurred costs necessary to comply with mandatory reliability standards issued pursuant to section 215 and (B) all prudently incurred costs related to transmission infrastructure development pursuant to section 216."[15] These words do far more than "codify" the just and reasonable standard; they command the Commission to use its discretion under section 205 to promote capital investment. Furthermore, Congress in section 219 even highlighted the importance of investment in economically or technologically efficient transmission infrastructure.[16] Section 219 was enacted against the backdrop of a long decline in transmission investment that is imposing substantial costs – in congestion and service interruptions – on consumers. If Congress had deemed our existing practices sufficient to reverse this trend, there would have been little need to enact section 219. Section 219 does not simply "codify" our legal authority; it requires us to take affirmative action to promote new investment. Although the resulting rates must be just and reasonable, the Commission has significant discretion under section 205 in

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[15] 16 U.S.C.A. 824s(a), (b)(1)-(4) (West Supp. 2006).

[16] <u>See</u> <u>id</u>. at 824s(a) and (b)(3).

making that determination and section 219 provides clear direction that we use that discretion to promote new infrastructure, not simply maintain the status quo.

15. While section 219 requires us to do more than maintain the status quo for transmission pricing, we recognize that our traditional ratemaking authority also requires us to establish a return on a public utility's assets that is "reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate to maintain and support its credit and enable it to raise money necessary for the proper discharge of its public duties"[17] and "should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."[18] Thus, a base-level ROE sufficient to promote capital investment in transmission facilities historically has not been considered an "incentive," but a requirement of establishing a just and reasonable rate.[19] In this regard, we recognize that our responsibilities under

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[17] Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679, 693 (1923).

[18] FPC v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).

[19] In contrast to a base-level ROE that reflects the financial and regulatory risks of an investment, an "incentive" has been more typically associated with specific basis point additions to a base ROE to satisfy discrete policy objectives. See, e.g., Western Area Power, 99 FERC ¶ 61,306, reh'g denied, 100 FERC ¶ 61,331 (2002) (Western), aff'd sub nom. Public Utilities Commission of the State of California v. FERC, 367 F.3d 925 (D.C. Cir. 2004); Michigan Electric Transmission Co., LLC, 105 FERC ¶ 61,214 (2003) (METC); American Transmission Company, L.L.C., 105 FERC ¶ 61,388 (2003) (American Transmission); ITC Holdings Corp., 102 FERC ¶ 61,182, reh'g denied, 104 FERC ¶ 61,033 (2003) (ITC Holdings); Regional Transmission Organizations, Order No. 2000, 65 FR 809 (Jan. 6, 2000), FERC Stats. & Regs. ¶ 31,089 (1999), order on reh'g,

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section 205 and our responsibilities under section 219 overlap in significant ways. We recognize that it may be difficult to meaningfully distinguish between an ROE that appropriately reflects a utility's risk and ability to attract capital and an "incentive" ROE to attract new investment. Notwithstanding this difficult distinction, consistent with Congress' direction in section 219, we are obligated to establish ROEs for public utilities that both reflect the financial and regulatory risks attendant to a particular project and that are sufficient to actively promote capital investment. We will do so within the zone of reasonableness, including above the midpoint where appropriate, to accomplish these regulatory responsibilities.[20] This end-result ROE, whether characterized as an incentive pursuant to section 219 or as a base-level ROE consistent with the just and reasonable standard of section 205, will take into consideration financial and regulatory risks

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Order No. 2000-A, 65 FR 12088 (Mar. 8, 2000), FERC Stats. & Regs. ¶ 31,092 (2000), aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001) (Order No. 2000). Section 219 addresses both situations. In addition to requiring the Commission to establish, by rule, incentive rate treatments to promote transmission investment generally, section 219 also requires the Commission to establish incentive-based rates to encourage transmission technologies and other measures to increase the capacity and efficiency of existing transmission facilities. Thus, Congress intended for us to establish an ROE sufficient to reflect financial and regulatory risks and also to consider discrete ROE incentives for, among other things, participation in transmission organizations, projects with particular benefits to reliability or reducing congestion, new technologies and efficiency enhancements.

[20] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 93.

attendant to the project and thereby satisfy Congress' direction that the Commission "provide a return on equity that attracts new investment in transmission facilities . . . ."[21]

C. Nexus Requirement

16. In the Final Rule, the Commission stated that the applicant must demonstrate that: (1) the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219; (2) there is a nexus between the incentive sought and the investment being made; and (3) the resulting rates are just and reasonable.[22] The Commission stated that an applicant is not required to show that, but for the incentives, the expansion would not occur because Congress did not require such a showing. Nevertheless, the Commission maintained that it will require applicants to show some nexus between the incentives being requested and the investment being made, i.e., to demonstrate that the incentives are rationally related to the investments being proposed.[23]

1. Rehearing Requests

17. Industrial Consumers oppose allowing applicants to request multiple incentives, arguing that the Commission erred by determining that section 219 does not require applicants to demonstrate a relationship between an incentive proposal and transmission

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[21] 16 U.S.C.A. 824s(b)(2) (West Supp. 2006).

[22] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 2, 26.

[23] Id. P 26, 48.

investment.[24] According to Industrial Consumers, the just and reasonable requirements of section 219(d) require that incentive rates must be based on a showing that there is a relationship between increased rates and the attraction of new capital.[25] They assert that customers should not be forced to pay for incentives unless those incentives are actually necessary to deliver additional transmission capacity. Therefore, Industrial Consumers claim that contrary to the Commission's conclusion, section 219 does not authorize the Commission to depart from judicial precedent on just and reasonable incentive rates.[26] Further, to the extent that the Commission relies on non-cost factors in determining just and reasonable incentive rates, the Commission must specify the nature of the relevant non-cost factors and offer a reasoned explanation of how the factors justify the resulting rates.[27] Industrial Consumers contend that the reasoned explanation must calibrate the relationship between increased rates and the attraction of new capital, ensure that the increase is in fact needed, and is no more than needed to accomplish the objective.[28]

18. APPA/NRECA also argue that applicants must demonstrate a need for the incentive rate treatments and make a showing sufficient for the Commission to find that a

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[24] Industrial Consumers at 3-7.

[25] Id. at 4, citing Farmers Union Cent. Exch. v. FERC, 734 F.2d 1486, 1503 (D.C. Cir. 1984) (Farmers Union).

[26] Id. at 5.

[27] Id. at 6-7

[28] Id.

particular incentive rate treatment "is in fact needed and no more than is needed" under the FPA and the Administrative Procedure Act.[29] APPA/NRECA consider the nexus requirement to be inadequate because it fails to require applicants to show that a particular rate treatment is actually a lawful incentive under sections 205 and 219 of the FPA.[30] They assert that under the nexus requirement, an applicant could show a sufficient rational relationship merely by claiming that granting the incentive rate treatment will make the investment more profitable and thus more attractive to investors.[31] TDU Systems repeat these points and claim that the nexus requirement will have no effect on the granting or denying of incentive applications unless the Commission provides concrete examples of categories of asserted relationships between proposed incentives and facilities that will not satisfy the nexus requirement. They also do not consider the nexus requirement to be a reasonable substitute for a cost-benefit analysis.[32]

19. Likewise, TAPS argues that the nexus requirement is unduly vague because it fails to clearly require a causal connection between the incentive and consumer benefits. TAPS asserts that the nexus requirement should test whether a requested incentive would

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[29] 5 U.S.C. 556 (2000).

[30] APPA/NRECA at 22.

[31] Id. at 23, citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 91, 117, and 133.

[32] TDU Systems at 19-20.

reasonably be expected to cause either a net decrease in delivered power costs even after considering incentive-increased transmission costs, or, where the expected net effect on delivered power costs is an increase, reliability gains that make that increase worthwhile.[33] To remedy the alleged deficiencies of the nexus requirement, TAPS proposes that the nexus requirement be revised to provide: "that the incentive sought is designed to result in those facilities being invested in, completed, and placed into service."[34] TAPS also recommends that the rule be amended to explicitly retain a reasonable calculation test, so that the Commission can determine which incentives return net consumer benefits and will be able to verify the accuracy of its prediction that granting incentives will spur increased investment.[35]

2. Commission Determination

20. Petitioners raise two related objections to the nexus requirement: (i) that it is too vague and therefore will be too easy to satisfy, and (ii) because it is not sufficiently rigorous, a different standard should be adopted. We address each in turn.

21. The required nexus test requires an applicant to demonstrate that the incentives being requested are " tailored to the risks and challenges faced" by the project.[36] By this

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[33] TAPS at 8-9.

[34] Id. at 11.

[35] Id. at 16, citing City of Charlottesville v. FERC, 661 F.2d 945, 955 (D.C. Cir. 1981).

[36] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 26.

we mean that the incentive(s) sought must be tailored to address the demonstrable risks and challenges faced by the applicant in undertaking the project.[37] The required nexus test therefore satisfies the Industrial Consumers request that there be a relationship between the rate treatments sought and the attraction of new capital.[38] It also satisfies TAPS' request that "the incentive sought is designed to result in" new facilities being constructed.[39] We disagree with TAPS and APPA/NRECA, however, that the test is designed to be lenient or that it will necessarily be satisfied in every case. As we indicated in the Final Rule, "[n]ot every incentive will be available for every new investment. Rather, each applicant must demonstrate that there is a nexus between the incentive sought and the investment being made."[40] In evaluating whether the applicant has satisfied the required nexus test, the Commission will examine the total package of incentives being sought, the inter-relationship between any incentives, and how any requested incentives address the risks and challenges faced by the project.

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[37] We also note that the Commission retains its discretion to provide policy-based incentives. As the courts have said, even prior to our new authority in section 219, the Commission's incentive rate determinations "involve matters of rate design . . . [and] policy judgments [that go to] the core of [the Commission's] regulatory responsibilities." Maine Public Utilities Commission v. FERC, 454 F.3d 278, 288 (D.C. Cir. 2006). See also Permian Basin Area Rate Cases, 390 U.S. 747 (1968) (Permian).

[38] Industrial Consumers at 4.

[39] TAPS at 11.

[40] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 26.

22. TDU Systems complain that we did not provide "concrete examples" of showings that would either satisfy or fail the nexus test. Although that was not the purpose of the Final Rule – the purpose was to enunciate the criteria to be applied in individual cases – we did provide certain illustrations. For example, we emphasized the need for incentives for new transmission projects that can integrate new generation and load and thereby improve reliability and reduce congestion:

> New transmission is needed to connect new generation sources and to reduce congestion. However, because there is a competitive market for new generation facilities, these new generation resources may be constructed anywhere in a region that is economic with respect to fuel sources or other siting considerations (e.g., proximity to wind currents), not simply on a "local" basis within each utility's service territory. To integrate this new generation into the regional power grid, new regional high voltage transmission facilities will often be necessary and, importantly, no single utility will be "obligated" to build such facilities. Indeed, many of these projects may be too large for a single load serving entity to finance. Thus, for the Nation to be able to integrate the next generation of resources, we must encourage investors to take the risks associated with constructing large new transmission projects that can integrate new generation and otherwise reduce congestion and increase reliability.[[41]]

We also emphasized that "this does not mean that every new transmission investment should receive a higher return than otherwise would be the case. For example, routine

[41] Id. P 25.

investments to meet existing reliability standards may not always …, qualify for an incentive-based ROE."[42]

23. The Commission reaffirms that the most compelling case for incentives are new projects that present special risks or challenges, not routine investments made in the ordinary course of expanding the system to provide safe and reliable transmission service. We therefore reject the arguments of EEI and Southern Companies that such routine investments should be treated the same, for purposes of applying the required nexus test, as new projects that present special risks or challenges.[43]

24. We also believe that the guidance provided in the Final Rule is sufficient. The purpose of the Final Rule was to establish criteria to be applied in individual cases, not to provide an exhaustive list of situations where incentives will be granted or denied. The decision whether to grant or deny incentives to a particular project is appropriately the subject of an individual rate application (or declaratory order) where the Commission can evaluate whether the applicants have fully supported any incentive rate treatments being sought.

25. We now turn to the alternative tests advocated by petitioners, discussing the "but for" test in this section and the "cost-benefit" test in the following section. The Final Rule rejected a "but for" test as inconsistent with Congressional intent in enacting section

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[42] Id. P 27.

[43] See infra P 52.

219.[44] We reaffirm that finding here. In doing so, we emphasize that both the required nexus test and the "but for" test share one thing in common: their common objective is to ensure that incentives are not provided in circumstances where they do not materially affect investment decisions. They differ sharply, however, in the means by which they seek to achieve that objective. The "but for" test requires an applicant to show that a facility would not be constructed unless the incentive is granted. We reject that test because it erects an evidentiary hurdle that could only, in very rare cases, be satisfied. There are many impediments to investing in new transmission, including siting concerns, financing challenges, rate recovery concerns, etc. It is therefore unreasonable to expect or require an applicant to show that a facility could not be constructed "but for" the removal of a <u>single</u> impediment – <u>e.g.</u>, increased cash flow through 100 percent construction work-in-progress (CWIP) or an enhanced ROE. This test could rarely, if ever, be satisfied, particularly given that incentives are ordinarily sought <u>before</u> investment decisions are made and, hence, before any siting impediments are even confronted.

26. The Commission therefore reaffirms its rejection of the "but for" test as the appropriate test for applying section 219. It would erect a barrier that is nearly impossible to meet and is thereby fundamentally incompatible with Congressional intent in enacting section 219. In enacting EPAct 2005, Congress plainly understood that there

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[44] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 48.

are many impediments to new transmission investment. Congress therefore took a variety of actions to address that problem, including giving the Commission backstop siting authority, requiring that entities have long-term transmission rights to support new investment and, in section 219, providing appropriate rate incentives. We decline to render section 219 essentially an empty letter by requiring the demonstration of a negative – that absent an incentive rate treatment, under no circumstance would a transmission project possibly be built. This would be directly contrary to the intent of Congress to encourage the construction of needed transmission.

27. We will grant rehearing, however, in one respect. The Final Rule states that the nexus test is to be applied separately to each incentive, rather than to the package of incentives as a whole. We agree that this approach fails to protect consumers where an applicant seeks incentives that both reduce the risk of the project and offer an enhanced ROE for increased risk. Even though the applicant no longer has to apply the nexus requirement separately to each incentive, the applicant will be required to demonstrate that the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant. In presenting a package to the Commission, applicants must provide sufficient explanation and support to allow the Commission to evaluate each element of the package and the interrelationship of all elements of the package. If some of the incentives would reduce the risks of the project, that fact will be taken into account in any request for an enhanced ROE. We are revising § 35.35(d) to reflect this clarification.

D. Cost-Benefit Analysis

28. In the Final Rule, the Commission adopted the proposal in the NOPR not to require applicants for incentive-based rate treatments to provide cost-benefit analyses. The Commission noted that courts have recognized that the Commission may consider non-cost factors in its ratemaking decisions.[45] Therefore, the Commission stated that it may consider non-cost factors as well as cost factors and that it will consider the justness and reasonableness of any proposal for incentive rate treatment in individual proceedings.

1. Rehearing Requests

29. TDU Systems and APPA/NRECA contend that the Final Rule's failure to require that incentive rates be justified by a cost-benefit analysis is inconsistent with sections 205 and 219 of the FPA. They assert that the Commission needs the information in the cost-benefit analysis to determine whether a particular incentive rate is just and reasonable, i.e. whether its cost is outweighed by the benefits customers will receive.[46] APPA/NRECA also contend that the Commission has no basis for concluding that a particular incentive provides consumers with a net benefit, as required under section 219(a), without a cost-benefit analysis.[47] TDU Systems also point out that the Commission and affected

[45] Id. P 65, citing Permian, 390 U.S. 747, 815 (1968); Pub. Utils. Comm'n of Cal. V. FERC, 367 F.3d 925, 929 (D.C. Cir. 2004) (CPUC v. FERC); Maine Pub. Utils. Comm'n. v. FERC, 454 F.3d 278, slip op. at 19 (D.C. Cir. 2006) (Maine PUC v. FERC).

[46] APPA/NRECA at 26; TDU Systems at 11.

[47] APPA/NRECA at 26-27.

customers must have the information necessary to distinguish between proposed projects that would benefit customers a great deal and proposed projects that would benefit customers minimally if at all.[48] Further, in considering non-cost factors, these parties argue that the Commission cannot make a reasoned decision about the appropriateness of non-cost factors in approving an incentive rate without first knowing the costs and benefits of the incentive rate.[49] They assert that intervenors also need this information to evaluate the impact of the rate proposal on them and to understand how much the applicant is relying on non-cost considerations. Moreover, APPA/NRECA contend, if the applicant is not required to present any evidence that consumers obtain net benefits from an increase in their transmission rates, the Commission cannot strike a fair balance between the financial interests of the regulated company and the relevant public interests, both existing and foreseeable.[50] Further, TDU Systems and APPA/NRECA state that the plain language of section 219 demonstrates that Congress' intent is to promote only efficient investment, investment that benefits consumers. They assert that Congress' unqualified adoption in section 219(d) of the statutory just and reasonable standard demands a cost-benefit analysis.

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[48] TDU Systems at 12.

[49] Id. at 15; APPA/NRECA at 27.

[50] APPA/NRECA at 29, citing Farmers Union, 734 F.2d at 1502 .

30. TDU Systems and APPA/NRECA also argue that elimination of the cost-benefit analysis will be harmful to customers because of the two-stage application procedure.[51] They assert that applicants should be required to provide the Commission and customers with all relevant facts concerning costs and benefits at the petition for declaratory order stage, where the applicant's right to the incentive will be decided, because the Final Rule precludes relitigation of these issues in the later section 205 proceeding.[52] They state that the interested parties must have the information needed to raise specific issues as to whether the likely customer benefits of the project justify the likely costs of the incentives to be awarded. They also argue that without a rigorous cost-benefit analysis at the initial stage, the benefits that formed the Commission's initial approval would be so amorphous that there would be little objective data for the Commission to assess in its periodic progress assessments. Allowing recipients of incentives to fix the term of their incentive-rate awards in the absence of a rigorous initial cost-benefit analysis would serve only to perpetuate the contravention of the statutory just and reasonable standard, according to APPA/NRECA. TDU Systems agree, stating that they can perceive no

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[51] Under the Commission's two-stage application procedure, an applicant can petition for a declaratory order seeking an incentive-based rate treatment for its project. After the Commission issues the declaratory order, the applicant must seek to put the rates into effect through a separate single-issue or comprehensive section 205 filing. See Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 76-78.

[52] TDU Systems at 12-14; APPA/NRECA at 29-30.

justification for allowing incentive awardees to define the duration of their own awards in the absence of a rigorous initial cost-benefit analysis.

31. Industrial Consumers argue that the Commission impermissibly departed from Order No. 2000,[53] without a reasoned explanation, by eliminating the cost-benefit analysis. They assert that the Commission wrongly concluded that the cost-benefit analysis is not necessary because customers will be protected by the Commission's review of applications pursuant sections 205, 206, and 219 of the FPA, which require that all rates be just and reasonable and not unduly discriminatory or preferential.[54] They state that in Order No. 2000, the Commission required applicants for innovative transmission rate treatments to demonstrate how the investment in the transmission system benefits consumers and to provide a cost-benefit analysis, including rate impacts. Such a disconnect with Commission precedent reflects an absence of reasoned decision making.[55]

32. Further, Industrial Consumers contend that, to successfully balance the competing interests of providing incentives to encourage transmission investment and its statutory responsibility of protecting customers from excessive rates, the Commission must narrowly tailor incentives that require a close calibration between the increased rates and

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[53] Order No. 2000, supra note 19.

[54] Industrial Consumers at 7-8.

[55] Id.

a corresponding level of benefits. Without such a close calibration between the proposed incentive rates and the anticipated benefit, the Commission risks thwarting the just and reasonable requirements of the FPA. Thus, according to Industrial Consumers, applicants for incentive treatment must be required to demonstrate that incentives will actually yield a positive return in the form of otherwise unachievable reliability improvements and reduced congestion costs.[56]

33. SMUD contends that the nexus requirement is not sufficient to justify eliminating the cost-benefit analysis required under Order No. 2000. It asserts that there is no connection between the lawfulness of non-cost factors and the elimination of the cost-benefit test for incentive rates. SMUD states that, while the Commission recognized the non-cost-based nature of incentive ratemaking in the 1992 Policy Statement, the Commission, nonetheless concluded that benefits to consumers must be quantifiable, and SMUD asserts that nothing in section 219 alters the requirement for a cost-benefit test.[57] Further, SMUD contends that the nexus test results in a lower burden of proof for applicants without explaining why a cost-benefit test is no longer necessary. SMUD requests the Commission to clarify that the incentives for new construction to reduce congestion will be capped so that the delivered cost of power to the consumer is lower

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[56] Id. at 10.

[57] SMUD at 2, citing Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities: Policy Statement on Incentive Regulation, 61 FERC ¶ 61,168 at 61,590 (1992) (1992 Policy Statement).

than what it was before the facilities were constructed, thereby ensuring that consumers will not pay incentive rates for congestion-reducing construction unless the result is a lower cost of delivered power. SMUD also requests clarification that incentives for reliability upgrades will not reward the construction of more transmission capacity than is reasonably necessary to meet new reliability standards, thereby ensuring that incentive payments for reliability improvements will not be awarded for more than what is needed to ensure reliability.

34. TAPS asserts that the Commission's authority to award above-cost incentives has always turned on whether the incentive's cost is outweighed by the benefits customers will receive.[58] TAPS advocates that the Final Rule be amended to explicitly retain a reasonable calculation test that analyzes which incentives spur increased investment, and require the Commission to use this test to replace the cost-benefit requirement.

2. Commission Determination

35. The Commission reaffirms the decision not to adopt a "cost-benefit" analysis for four principal reasons.

36. First, the arguments in favor of a cost-benefit analysis start from the premise that our traditional approach to setting transmission rates is fully sufficient to attract new transmission investment in all cases. This premise cannot be squared with section 219. As discussed above, section 219 was enacted to counteract a long decline in transmission

[58] TAPS at 9, citing CPUC v. FERC, 367 F.3d at 929.

investment. Its provisions are mandatory, not permissive, and they proceed from the premise that the Commission must use its full discretion under section 205 to "promot[e] capital investment." It did not, as noted above, simply codify the status quo; it required the Commission to pass a new rule adopting incentive-based rate treatments.

37. These facts readily distinguish the Final Rule from prior instances where the Commission required a cost-benefit analysis.[59] None of those policies was adopted in response to a Congressional directive to use the Commission's discretion under section 205 to address a national problem – the decline in transmission investment that is threatening reliability and imposing billions of dollars in congestion costs on consumers.

38. Second, petitioners fail to recognize that applicants will be required to show that all rates are just and reasonable under section 205. For example, any ROE will remain within the range of reasonable returns. Further, many of the incentives described in the Final Rule only change the timing of cost recovery (e.g., 100 percent CWIP), not the level of cost recovery. Others reduce the risks of investment (e.g., abandoned plant

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[59] Order No. 2000 required as a condition for any innovative transmission rate treatment that the applicant demonstrate “a cost-benefit analysis, including rate impacts.” 18 CFR 35.34(e)(ii) (2006). The Commission notes that in the 6 years since Order No. 2000 was issued, we have not received a single application seeking any of the innovative rate treatments that were provided for in that order. We believe that the requirement of a cost benefit analysis was perceived as an insurmountable hurdle which inhibited the utilities from seeking innovative rate treatments. Accordingly, in developing incentive rate treatments under section 219, the Commission expressly deleted the requirement for a cost-benefit analysis.

recovery), rather than changing the cost levels. We reiterate that each of the incentives adopted by the Final Rule is fully consistent with our responsibility to ensure that rates are just and reasonable under section 205.

39. Third, those advocating a cost-benefit analysis fail to recognize that the courts have held that the Commission may consider non-cost factors in setting rates.[60] Our authority to consider non-cost factors applies equally in the development of incentive rate-treatments.[61]

40. Finally, although the Commission is rejecting a cost-benefit analysis for the reasons stated above, applicants will nonetheless be required, as discussed above, to demonstrate the required nexus between the incentive being sought and the investment being made. This requirement will ensure that incentives are granted only where the incentives are tailored to address the demonstrable risks or challenges faced by the applicant.

E. Rebuttable Presumptions

41. In the Final Rule, the Commission adopted a set of processes that, if an applicant satisfies them, its project will be afforded a rebuttable presumption that it qualifies for transmission incentives. First, it created a rebuttable presumption that an applicant has

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[60] See Permian, 390 U.S. 747 at 791-2; CPUC v. FERC, 367 F.3d 925 at 929.

[61] Maine PUC v. FERC, 454 F.3d at 289 ("particularly in view of the [Commission's] authority to consider non-cost factors in setting rates, the State Commissions' position on calibration demands too much").

met the requirements of section 219 if that project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission.[62] Second, the Commission stated that regional planning processes can provide an efficient and comprehensive forum for evaluating transmission investments' qualifications under section 219 by looking at a variety of options across a large geographic footprint. For example, such a process has the ability to determine whether a given project is needed, whether it is the better solution, and whether it is the most cost-effective option among other alternatives.[63] The Commission also adopted a rebuttable presumption that an applicant has met the requirements of section 219 if a proposed project is located in a NIETC or has received construction approval from an appropriate state commission, agency or state siting authority.[64] The Commission also stated that "other applicants not meeting these criteria may nonetheless demonstrate that their project is needed to maintain reliability or reduce

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[62] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 58.

[63] Id. The Commission noted that the value of regional planning was expressly recognized when it proposed to amend the pro forma Open Access Transmission Tariff of jurisdictional public utilities to require regional planning to ensure that transmission is planned and constructed on a nondiscriminatory basis to support reliable and economic service to all eligible customers in the region. See Preventing Undue Discrimination and Preference in Transmission Service, Notice of Proposed Rulemaking, 71 FR 32,536 (June 6, 2006), FERC Stats & Regs., Preambles ¶ 32,603 at P 36 (2006) (OATT Reform NOPR).

[64] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 58.

congestion by presenting [to the Commission] a factual record that would support such a finding."[65]

1. Rehearing Requests

42. NARUC and TAPS contend that the Final Rule's rebuttable presumption is not consistent with the statutory requirements of section 219. They state that there was no showing in the Final Rule that assessments in the regional planning processes satisfy the requirements of section 219 and there is no basis to assume that the criteria employed in regional planning processes utilize the criteria set out in section 219.[66] Therefore, they argue that it cannot be reasonably presumed that every project that is subject to regional planning will benefit customers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. NARUC further contends that incentives for using regional planning processes are inappropriate in view of the Commission's proposal in the OATT Reform NOPR to require all jurisdictional public utilities to engage in regional planning.[67] Under such a mandatory requirement, all projects will effectively qualify for the rebuttable presumption because all projects will, presumably, be included in approved regional plans.[68]

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[65] Id. P 57.

[66] NARUC at 5-6; TAPS at 7-8.

[67] See OATT Reform NOPR, FERC Stats & Regs., Preambles ¶ 32,603 at P 36.

[68] NARUC at 6.

43. APPA/NRECA, NARUC, TDU Systems, and TAPS argue that the rebuttable presumption for state approvals should be deleted because there is no legal or logical basis to presume that projects falling into this category will ensure reliability or reduce the cost of delivered power.[69] They assert that the criteria applied by the state may not resemble the criteria that the Commission is required to apply under section 219 of the FPA. They argue that state commissions are mainly concerned with protecting retail customers in their respective states and state authorities apply state laws to construction-permit applications. Accordingly, states are not focused on public utility wholesale customers who may be in other states, or ensuring reliability or reducing transmission congestion. Therefore, APPA/NRECA assert that the Commission cannot delegate its responsibilities under section 219 to state authorities that may of necessity have a very different mission.[70]

44. NARUC also claims that projects receiving a designation as projects in NIETC should not receive a rebuttable presumption because such a designation, alone, cannot assure that the statutory prerequisites of section 219 have been satisfied when the criteria for NIETC designation do not mirror those set out for incentives under the statute.[71]

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[69] Id. at 7; TAPS at 6; APPA/NRECA at 37-39; TDU Systems at 25-27.

[70] APPA/NRECA at 38.

[71] NARUC at 7.

45. Additionally, NARUC, APPA/NRECA, and TDU Systems claim that the scope of the rebuttable presumption is ambiguous and needs to be clarified. They state that it is not clear to which part of the three-part showing that the rebuttable presumption applies to.[72] They state that the rebuttable presumption should only apply to the first part (ensure reliability or reduce the cost of delivered power by reducing transmission congestion) of the three-part showing because the only way an applicant can appropriately satisfy the statutory requirements of FPA section 219 is to demonstrate on the record that the project either ensures reliability or reduces the cost of delivered power and that the rates satisfy sections 205 and 206 of the FPA. Therefore, the applicant must still demonstrate with factual evidence that there is a nexus between the incentive sought and the investment being made and that the resulting rates are just and reasonable.[73] APPA/NRECA also request the Commission to clarify that this interpretation applies to both section 205 filings and petitions for declaratory order.[74] TAPS contends that the rebuttable presumptions conflict with the Commission's intended limitations on the receipt of incentives, such as routine investments, which may be included in a regional plan and

[72] Under section 35.35(d) of the regulatory text, an applicant for incentive rates is required to make a three-part showing that: (1) the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219; (2) there is a nexus between the incentive sought and the investment being made; and (3) resulting rates are just and reasonable. 18 CFR 35.35(d) (2006).

[73] APPA/NRECA at 35-36; NARUC at 7-8; TDU Systems at 24-25.

[74] APPA/NRECA at 36.

required to receive state siting approval prior to construction, but may not always qualify for an incentive-based ROE.[75]

2. **Commission Determination**

46. We will grant rehearing and clarification in part. The Commission created the rebuttable presumption for the purpose of avoiding duplication in determining whether a project maintains reliability or reduces congestion. We do not wish to repeat the work of state siting authorities, regional planning processes, or the DOE in evaluating these issues. However, we agree with NARUC that if such processes do not in fact include such a determination, a rebuttable presumption would not be appropriate. Accordingly, we grant rehearing and are modifying § 35.35 in three ways.

47. First, we agree with NARUC that the NIETC process will not necessarily determine that every transmission project within a designated corridor will meet the section 219(a) requirements, nor is DOE required to make such a determination. However, we do not believe it is necessary to retain this particular rebuttable presumption in our regulations because any project which is proposed in a NIETC will of necessity have to go through a state or federal siting process. If an applicant's proposed project is within a NIETC, we expect that it will be sited in most instances by the appropriate state siting authority and the applicant will be able to rely on the state siting rebuttable presumption for meeting the requirements of section 219(a). In those cases where

[75] TAPS at 8, citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 94.

projects within a NIETC are sited by this Commission pursuant to our new authority in section 216, an applicant may rely on our findings in our siting process for meeting the requirements of section 219(a).[76] Thus, applicants with projects in a NIETC have an opportunity to rely upon the appropriate siting processes to meet the requirement that a project ensure reliability or reduce the cost of delivered power by reducing transmission congestion, and we need not include the NIETC process as a rebuttable presumption.[77]

48. We are amending our regulations to provide that an applicant that obtains Commission authorization under section 216 to site electric transmission facilities in interstate commerce shall be deemed to satisfy the requirements of section 219(a).[78]

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[76] As stated in section 216, the Commission may exercise its new siting authority if inter alia it finds that the construction or modification of the facilities "significantly reduce transmission congestion in interstate commerce and protects or benefits consumers." Since the Commission is required to find that a project reduces transmission congestion before it can authorize the siting of a transmission facility within a NIETC, such facilities necessarily satisfy the requirement of section 219(a) and these regulations.

[77] While DOE is not required to determine whether all projects within a NIETC meet the pre-requisites of section 219, we anticipate that DOE is likely to consider whether transmission projects within these corridors ensure reliability or reduce the cost of delivered power by reducing transmission congestion. Thus, an applicant that does not rely upon a rebuttable presumption for meeting the pre-requisites of section 219 may nonetheless use the findings made by the DOE. Accordingly, the Commission will give due weight to the DOE's determinations concerning the ability of transmission projects within a NIETC to ensure reliability or reduce the cost of delivered power by reducing transmission congestion.

[78] Section 216(b)(4). See also Regulations for Filing Applications for Permits to Site Interstate Electric Transmission Facilities, Order No. 689, 71 FR 69,440 at P 41 (Dec. 1, 2006) ("The Commission will review the proposed project and determine if it reduces the transmission congestion identified in DOE's study and if it will protect or

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49. Second, we will modify our regulations to require each applicant seeking to invoke the rebuttable presumption to explain in its filing how the applicable process (regional planning or state approval) in fact considered whether the project ensures reliability or reduce congestion. We continue to believe that, these approval processes will, in all likelihood, examine whether the project maintains reliability or reduces congestion. But in instances where this is not the case the applicant will bear the full burden of demonstrating such facts.

50. Third, we also clarify that the rebuttable presumption applies only to the requirement that an applicant demonstrate, that a project is needed to ensure reliability or to reduce congestion. It does not apply to any other requirement in 18 C.F.R. § 35.35, such as the requirement, that the applicant demonstrate the required nexus between the incentive sought and the investment being made[79] and that the resulting rates are just and reasonable in either the petition for declaratory order or section 205 filing. We will modify our regulations accordingly.

F. ROE Sufficient to Attract Investment

51. In the Final Rule, the Commission adopted the NOPR's proposal to allow, when justified, an incentive-based ROE to all public utilities (i.e., traditional public utilities and

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benefit consumers. It will investigate and determine the impact the proposed facility will have on the existing transmission grid and the reliability of the system").

[79] We note that the Final Rule's statement regarding routine investment cited by TAPS, applies to the nexus demonstration, and therefore there is no conflict between the rebuttable presumption and that statement.

Transcos) for new investments in transmission facilities that benefit consumers by ensuring reliability or reducing the cost of delivered power by reducing congestion.[80] By including this provision in the Final Rule, the Commission stated that it satisfied the requirement of section 219 to provide an ROE that attracts new investment in transmission facilities (including related transmission technologies). The Commission stated that it will provide ROEs at the upper end of the zone of reasonableness for transmission investments that meet the requirements of section 219. Further, the Commission clarified that it will continue to use the DCF analysis for ROE determinations.[81] The Commission also noted that not every investment that increases reliability or reduces congestion will qualify for an incentive-based ROE. For example, routine investments may continue to be assessed under traditional ROE determinations because there is an obligation to construct them and high assurance of recovery of the related costs.[82]

1. Rehearing Requests

52. EEI and Southern Companies take exception to the statement in the Final Rule that "routine investments made to comply with existing reliability standards may not always

[80] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 91.

[81] This analysis, undertaken in individual rate applications, assesses representative proxy companies and the impact of other factors, including risk, on the zone of reasonableness for ROE. Id. P 92.

[82] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 94.

qualify for an incentive-based ROE."[83] They argue that the statement discriminates against projects or upgrades that may be proposed to address reliability concerns, and therefore the statement should be deleted.[84] Southern Companies emphasize that the statutory requirement under 219 makes no distinction between routine or non-routine status; therefore, regardless of status, an investment that promotes reliability should be entitled to incentive rate treatment. In that respect, Southern Companies request the Commission to confirm that all reliability-related investments qualify for incentive-based ROEs.[85] Furthermore, Southern Companies request the Commission to clarify that a single incentive-based ROE should apply to all, not just new, transmission investment.[86]

53. TDU Systems contend that the Commission should reconsider its commitment to grant incentive applicants an ROE at the upper end of the zone of reasonableness. Specifically, TDU Systems claim that the Commission may have difficulty handling all the rate filings that seek extremely high ROEs because of the two-stage process. They

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[83] Id.

[84] EEI at 11; Southern Companies at 3.

[85] Southern Companies at 4.

[86] Southern Companies argue that section 219(b)(2) should be read to require the Commission to re-examine its ratemaking methods and revise it current ROE policies for all transmission investment, and that the base ROE must be sufficient to attract new investment. It contends that Congress did not state that the Commission shall provide a return on equity **for** new investment in transmission. Instead, section 219(b)(2) states that the Commission shall "provide **a** return on equity that attracts new investment in transmission." See Id. at 5 (emphasis provided by commenter).

contend that the Commission is placing too much reliance on its ability to protect consumer interests in the second stage, section 205 review, and recommends that the Commission relieve some of the pressures by giving incentive applicants a more specific message that the incentives have limits.[87] APPA/NRECA also assert that the Commission has not explained why such an increase in allowed ROEs is, or could be, either necessary to attract capital or otherwise just and reasonable and that the rule does not balance investor and consumer interests in setting incentive ROEs.[88] Accordingly, these parties assert that the Commission should permit incentives only if the package as a whole results in a just and reasonable rate. In so doing, they argue, the Commission should disavow any intent to allow ROEs near the top of the zone of reasonableness and ensure that companies in the proxy group with ROEs at the top of the zone of reasonableness do not become the basis for determining the zone, particularly to the extent incentive ROEs become the base case in future DCF analyses.

54. Similarly, TAPS argues that the Commission must be prepared to apply a much stricter scrutiny to the composition of the proxy group that determines the range of the zone of reasonableness to the extent the Commission continues to declare in favor of

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[87] TDU Systems at 27-29.

[88] APPA/NRECA at 9, 47.

rates set at the top of a range that has not yet been established.[89] Also, TAPS recommends that the Commission modify its methodology for proxy results by first averaging the two results per proxy company so that there is one, average result per proxy company, as it does in gas cases,[90] thereby providing a more defensible basis for just and reasonable returns. TAPS requests the Commission to clarify that it will ensure that the top of the range does not become a self-escalating spiral with the highest proxy result reflecting an investor expectation that the proxy itself will garner above-cost incentive profits.[91]

55. Southern Companies consider the Commission's continued reliance on DCF analysis in the Final Rule to be contrary to Congressional intent and policy.[92]

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[89] TAPS explains that many transmission owners will request rates at the high end of the zone of reasonableness and that the main restraint on transmission rates will be the ceiling that is set by the placement of the top of the zone of reasonableness. The zone has been defined by taking a sample group that includes a large number of proxy companies and calculating two data points per proxy. Each pair of points represents the extreme values for each company. The zone of reasonableness is often characterized as reaching up to the higher data point for the most extreme company in the proxy set. Thus, when the top of the range sets the return, it becomes critical to ensure that every company included in the proxy group very closely resembles the utility whose return is being capped, i.e., its capital structure, business risk, financial risk, and associated capital costs. See TAPS at 18-22.

[90] Id. at 21, citing High Island Offshore System, L.L.C., 110 FERC ¶ 61,043, at P 148 (2005).

[91] Id. at 22.

[92] According to Southern Companies, section 219's requirement that the Commission provide ROEs that are sufficient to attract new transmission investment is evidence of Congress' conclusion that the Commission's current ROE methodology is (continued)

Accordingly, Southern Companies request the Commission to clarify that it will allow the use of additional ROE estimation methodologies[93] because these methodologies will better ensure that an entity is ensured a reasonable rate of return. Southern Companies assert that failure to consider the results of more than one methodology, although there are other sound methods, constitutes arbitrary and capricious decision making.[94] Furthermore, Southern Companies consider the Final Rule's refusal to recognize the flaws in the current DCF analysis to be arbitrary and capricious and its finding that the DCF analysis yields just and reasonable results to be in error, particularly in light of the fact that the DCF analysis drives a utility's stock price to its book value while market values exceed book values by approximately 2.47 to 1 as of December 31, 2005 and the constant-growth DCF model often produces divergent and meaningless results.[95]

56. Southern Companies also argue that ROE adders should be provided to all new transmission construction. They assert that section 219 directs the Commission to promote investment of <u>all</u> facilities and therefore the Commission's determination in the

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not producing adequate results. Therefore, the Commission should construe section 219(b)(2) as a mandate from Congress to re-examine its traditional ratemaking policies. Southern Companies at 5-6.

[93] Such methodologies include the risk premium approach, the capital asset pricing model and the comparable earnings approach. <u>Id</u>. at 7.

[94] They state that using multiple methodologies recognizes that no single approach can accurately predict an appropriate ROE level so as to satisfy the constitutional and statutory requirements. <u>Id</u>. at 8.

[95] <u>Id</u>. at 11.

Final Rule that it will not create specific ROE adders is contrary to EPAct 2005 and requiring applicants to go through a rate case prior to receiving any incentives would unnecessarily impede Congress' stated goal of encouraging new transmission investment.[96]

57. The California Commission claims that the Commission did not engage in reasoned decision making in the Final Rule because it failed to consider risk assessment and did not address its arguments about the relative low risk of transmission investment.[97] It argues that the Commission failed to explain why transmission entities should be eligible for a higher ROE given the low risk associated with transmission investments. The California Commission states that transmission businesses have a low financial risk because they generate a steady revenue stream as a regulated monopoly. Also, among the three functions of an integrated utility's electricity business, i.e. generation, distribution, and transmission, the transmission business carries the lowest risk.[98] Further, the California Commission argues that the Commission did not consider the effect the multiple incentives created by the Final Rule will have on lowering the risk, such as 100 percent recovery of CWIP before a transmission project is used and useful. Accordingly,

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[96] Id. at 18.

[97] California Commission at 7-10.

[98] Id. at 8.

it contends that above-average ROEs for transmission are not needed to effect new transmission facilities.[99]

58. New England Commissions argue that the Commission arbitrarily, capriciously, and without a reasonable factual foundation, determined that ROE incentives encourage investment and make transmission projects attractive.[100] They state that the New England ROE proceeding in Bangor Hydro-Electric[101] demonstrated that an enhanced ROE will not change transmission owners' performance in any material respect, but will merely give them an unjust and unreasonable windfall. Accordingly, New England Commissions assert that the Commission's finding that transmission incentives are necessary is not supported by the record in this rulemaking or in the Bangor Hydro-Electric proceeding.[102] According to the New England Commissions, it is contrary to the directive in section 219(d) that rates be just and reasonable to dispense with any showing of need before awarding ROE incentives.[103] New England Commissions requests the Commission to clarify that it will judge the justness and reasonableness of ROE adders in

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[99] The California Commission states that even without the high ROE incentive, California IOUs have planned and constructed numerous transmission facilities in the last 10 years. Id. at 9.

[100] New England Commissions at 5.

[101] Bangor Hydro-Electric Co., 106 FERC ¶ 61,280 (2004).

[102] New England Commissions at 6-10.

[103] Id. at 12.

New England based on the record in Bangor Hydro-Electric proceeding and specify in the rule that only a case-by-case evaluation can determine whether an ROE incentive will produce justifiable benefits.

2. Commission Determination

59. We will grant rehearing and clarification in part on certain issues and deny rehearing on all other issues.

60. We reject the argument of investor-owned utilities that ROE incentives be applied without regard to the nature of the facility being constructed or the risks associated with it. Specifically, the Commission reaffirms that the most compelling case for incentive ROEs are new projects that present special risks or challenges, not routine investments made in the ordinary course. We therefore reject the arguments of EEI and Southern Companies that such routine investments should be treated the same, for purposes of applying the nexus test, as new projects that present special risks or challenges. Although we will consider applications for ROE incentives for all projects, we reiterate that not all projects will be able to meet the nexus requirement. EEI and Southern Companies have provided no compelling reason why a routine investment made in the ordinary course should, as a general matter, receive an incentive ROE

61. We also reject the argument that incentive ROEs should apply to existing transmission rate base that has already been built. The purpose of section 219 is to attract investment in transmission. Southern Companies have not provided any evidence that higher ROEs for transmission rate base that has already been built are necessary to ensure

reliability or to reduce congestion; nor have they shown why such ROEs are necessary to attract new investment in transmission.

62. We also reject the contentions of certain customer groups that incentive ROEs will "destabilize" the DCF methodology. First, as indicated above, all ROEs approved pursuant to section 219 will be within the range of reasonableness, as determined consistent with our precedents. Second, any incentive ROEs granted under 219 should have a minimal effect, if any, on the overall range of reasonableness derived from the appropriate proxy group. The DCF methodology uses proxy groups of entire companies, not individual transmission projects. In other words, the "cash flows" being measured in the DCF method are the cash flows of entire companies. These cash flows should not be significantly affected by an incentive return for any particular transmission project for one company within the proxy group. Moreover, to the extent there is any small effect on the overall range of reasonableness, it will appropriately reflect the substantial risks associated with constructing new transmission, as discussed above.[104]

63. We also reject requests to cease our utilization of the DCF method. Inasmuch as the DCF method yields just and reasonable rates, as the Commission has recognized in numerous proceedings, we see no basis to require other methods for the evaluation of incentive applications. As we stated in the Final Rule, the Commission will consider on a

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[104] The Commission retains the discretion to adjust ROEs if we find that the results of a DCF analysis do not accurately reflect the risk of the applicant and its ability to attract capital.

case-by-case basis whether the application of the traditional DCF analysis should be modified.[105]

64. We also do not consider the process for approving incentive ROEs, i.e., setting a zone of reasonableness and a DCF analysis requirement, to be an unnecessary impediment to encouraging transmission investment. Generic adders, as recommended by Southern Companies, would still require the Commission to make a determination that the proposed ROEs are just and reasonable, and its findings would have to be based on reasoned decision-making. Therefore, the Commission necessarily would be required to establish a zone of reasonableness and a justification for the approved ROEs.

65. Responding to the California Commission, the Final Rule explained the basis for its decision to provide an incentive ROE, based on the need to attract investment in the context of long-term industry underinvestment and the need to re-evaluate the balance of investor and ratepayer interests, and therefore has provided the reasons for its decisions. The Commission is not, in this rule, setting the incentive ROE, but rather leaves that determination to future proceedings that will authorize a unique ROE appropriate to the facts and circumstances of each applicant. It is in those proceedings that the California

[105] We agree with TAPS that averaging each company's low and high DCF return would result in a single average DCF result for each electric company, making it like the single DCF return for gas and oil pipelines, from which a median return on equity for the group can be calculated. While this is an acceptable method, we will not require use of that method in the Commission's DCF analysis because that issue is beyond the scope of this proceeding and is more appropriately addressed in the individual application proceedings.

Commission can raise its concerns regarding comparative returns within the energy industry and the specific characteristics of California utilities. However, we agree with the California Commission that utilities should consider the effect that certain incentives (e.g. CWIP in rate base, recovery of abandoned plant) may have on risk and that return on equity in the upper end of the zone of reasonableness may not be appropriate when combined with incentive rate treatments that lower overall risk.

66. We do not address the issues raised by New England Commission with respect to the Bangor Hydro-Electric proceeding because they have been addressed in a recent Commission order and are now pending on rehearing.[106]

67. We will, however, grant clarification in part. Several petitioners express the fear that the Commission will routinely grant ROEs at the top end of the zone of reasonableness. Although the Commission has broad discretion to establish returns on equity anywhere within the zone of reasonableness, we must be careful in the manner in which we exercise this discretion. The Commission clarifies that we do not intend to grant incentive returns "routinely" or that, when granted, they will always be at the "top" of the zone of reasonableness. Rather, each applicant will, first, be required to justify a higher ROE under the revised nexus test and, second, to justify where in the zone of reasonableness that return should lie. In some instances, where the risks or challenges faced by a new investment are substantial, we may grant an ROE at the top end of the

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[106] Bangor Hydro-Electric Co., Opinion No. 489, 117 FERC ¶ 61,129 (2006).

zone of reasonableness. However, we have no expectation of doing so in all cases or even routinely.

68. We also provide clarification on the timing of an ROE determination. In most instances, an ROE determination occurs in a hearing that considers the justness and reasonableness of the costs of the investment for purposes of setting rates under section 205. In that hearing, the overall range of reasonableness would be established, as well as a determination of where within that range the ROE should be set. If the Commission granted a request for an incentive ROE at the upper end of that range in a petition for declaratory order, the hearing would establish where in the upper end the ROE would fall – whether at the top end or at a different point in the upper end of the range. The Commission would then review any determination by an administrative law judge on that issue.

69. We recognize, however, that our hearing procedures for determining ROE can create uncertainty for investors. Under traditional ratemaking processes, the rates for a particular project, including the ROE for that project, are determined only <u>after</u> an investment decision is made and the facility is constructed. This may provide a disincentive to new investments that are sensitive to our ROE determinations. Although our processes are designed to provide a just and reasonable return, we recognize that there can be significant uncertainty as to the ultimate return because of the uncertainties associated with administrative determinations (<u>e.g</u>., selection of the proxy group, changes

in growth rates, etc.) This can itself constitute a substantial disincentive to new investment.

70. Recognizing this, we will clarify the approach adopted in the Final Rule. We will continue to allow applicants to request, in a petition for declaratory order, an ROE that is at the upper end of the zone of reasonableness and, in such instances, the ultimate ROE will be determined in the hearing process. However, if an applicant desires up-front certainty of the ROE it will receive, we clarify that we also will consider requests for -declaratory orders that set the ROE for a particular project, and that include the appropriate support for the ROE, including, for example, a DCF analysis. An applicant seeking to use this process will have to meet the required nexus requirement, such as by showing that an up-front ROE determination is important for its investment decision. An applicant seeking such an up-front ROE determination also may request an ROE at the upper end of the zone of reasonableness; however, the fact that an up-front ROE determination is itself an incentive that tends to reduce risk will be taken into account in considering any such request.

G. <u>Incentives Available to Transcos</u>

71. In the Final Rule, the Commission approved incentive-based rate treatments applicable to Transcos to encourage Transco formation and attract investment.[107]

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[107] Section 35.35(b)(1) defines Transcos as stand-alone transmission companies approved by the Commission that sell transmission services a wholesale and/or on an (continued)

Specifically, the Commission approved an ROE that encourages Transco formation and is sufficient to attract investment and an adjustment to book value of transmission assets being sold to a Transco to remove the disincentive associated with the impact of accelerated depreciation on federal capital gains tax liabilities.[108] The Commission noted that its decision to approve such incentives for Transcos is based on the "proven and encouraging track record of Transco investment" in transmission facilities.[109]

1. Rehearing Requests

72. EEI argues that applicants seeking transmission incentives should be treated equally, without regard to their form of business. It argues that the incentives applicable to stand-alone transmission companies should be expanded to apply to all transmitting utilities.[110] EEI also urges the Commission to recognize that all forms of transmission business models can effectively provide transmission facilities and to reiterate that it will evaluate each applicant's proposed incentives, in particular the upper range of reasonable

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unbundled retail basis, regardless of whether they are affiliated with another public utility.

[108] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 222-224. The incentive ROE does not preclude a Transco from applying for other incentives, including hypothetical capital structure, allowance for deferred income taxes (ADIT), acquisition premiums, formula rates or deferred cost recovery. Id. P 221.

[109] See id. P 221-23.

[110] EEI at 5, 7-9.

ROEs, without regard to the applicant's form of business and without bias as between forms of business.[111]

73. Southern Companies contend that additional incentives for Transcos are not justified on grounds that the Transcos have a good record of transmission investment.[112] They state that vertically-integrated utilities like Southern Companies have consistently invested significantly in transmission maintenance and expansion. Southern Companies also claim that special ROE incentives solely for Transcos would be discriminatory by favoring one corporate structure over another to the extent both business structures have similar transmission investment records[113] and the requirements of section 219 to promote investment regardless of the ownership of the facilities.

74. APPA/NRECA assert that because the Commission's definition of Transcos includes affiliated Transcos under the control of one or more parent public utilities, granting incentive rate treatment greater than that afforded to public utilities would constitute a financial windfall.[114] They argue that such affiliated Transcos should not be

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[111] Id. at 5. EEI claims that section 219(b) provides that the rule shall promote transmission investment "regardless of the ownership of facilities" and the Commission noted in the Final Rule that it will not limit incentives based on corporate structure or ownership. Id. at 7, citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 4, 225.

[112] Southern Companies at 16-17.

[113] Id. at 17, citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 225.

[114] APPA/NRECA at 31, 34-35. In the Final Rule, the Commission stated that the definition of Transco does not exclude affiliated Transcos with active ownership by market participants, or stand-alone transmission companies that own transmission and

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eligible for special incentive rate treatment because such a payment would neither induce new construction nor provide any new benefit to the customer paying the incentive rate.[115]

75. Furthermore, TDU Systems oppose passive ownership interests in Transcos and contend that, if authorized, passive ownership interests should only be authorized upon a showing that the option of investment in the Transco is open to all load-serving entities (LSEs) in the region up to their load ratio shares.[116] They also argue that the Commission must rigorously scrutinize and monitor relationships among the passive owners to deter the potential for abuse. TDU Systems also contend that the Commission should clarify that Transcos may only receive incentive rates if there are no interests within the Transco competing with transmission for capital. They recommend that the Commission condition the granting of incentives by imposing limits on business investments in other industries to avoid the dilution of capital funding from competing sources within the company.[117] They also claim that incentives for new investment in transmission

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distribution facilities. The Commission said that it would consider the eligibility of such arrangements based on a showing of how the specific characteristics of a proposed Transco affect its ability and propensity to increase transmission investment and lead to increased transmission investment similar to Transcos the Commission already approved. See Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 202.

[115] APPA/NRECA at 31.

[116] TDU Systems at 39.

[117] Id. at 40.

infrastructure should not be necessary because, as the Commission noted in the Final Rule, such incentives are inherent in the corporate business model to encourage investment.[118] Therefore, encouraging additional incentives provides no incremental benefit to consumers.[119]

2. Commission Determination

76. We affirm the finding in the Final Rule that the Commission will not limit an applicant's ability to seek incentive-based rate treatments based on corporate structure or ownership.[120] The Commission will evaluate these applications to determine if incentive treatment is justified based on their demonstrations that the projects meet the requirements of section 219 and this rule. Certain types of incentives, such as the ADIT incentive may be more appropriate where transmission is being spun off or otherwise transferred to a new corporate entity, such as a Transco. But we see no basis for the claim that the Transco incentives are unduly discriminatory or contrary to the goals of section 219.

77. The Final Rule described at great length the very significant transmission investment that has been undertaken by Transcos, to date.[121] There is no reason to repeat

[118] See Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 204.

[119] TDU Systems at 41.

[120] See Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 4.

[121] Id. P 222-23.

those examples again here, but we disagree with comments that suggest that Transcos do not have a good record of transmission investment. Furthermore, their singular focus on transmission investment by transmission-only companies, the elimination of competition for capital between generation and transmission investments, and the access to capital markets have all been cited in support of the value of the Transco business model for getting new transmission built. For all of these reasons, the Commission adopted incentive-based rate treatments applicable to Transcos that would both encourage Transco formation and attract investment.

78. As we stated in the Final Rule, the Commission will consider concerns regarding affiliated Transcos in specific applications for incentive treatment.[122] We believe the Final Rule fulfills the requirements of section 219 by determining eligibility for Transco status and incentive-based rate treatment based on a showing of how the specific characteristics of a proposed Transco affect its ability and propensity to increase transmission investment in individual case proceedings. Therefore, we do not consider this proceeding to be the appropriate forum for adopting preconditions related to other issues, such as affiliation or passive ownership. Inasmuch as Transcos are subject to the Commission's market behavior rules, their activities will be monitored for any potential market abuse. Therefore, we affirm the availability of ROE incentives to Transcos. As stated in the Final Rule, we expect that the incentive ROE will be used for additional

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[122] See id. P 202.

capital spending, and thereby provide consumer benefits, as demonstrated by the negative cash flow profiles of Transcos and their future capital spending plans.

H. Transmission Organization Incentive

79. In the Final Rule, the Commission stated that it will authorize, when justified, an incentive-based rate treatment for public utilities that join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization.[123] Applicants for the incentive-based rate treatment must make a filing with the Commission under section 205 of the FPA. For purposes of section 35.35(e), an incentive-based rate treatment means an ROE that is higher than the ROE the Commission might otherwise allow if the public utility were not a member of a Commission-approved Transmission Organization. The Commission stated that it will not create a generic adder for such membership, but instead will consider appropriate ROE incentives on a case-by-case basis. The Commission also stated that transmitting utilities or electric utilities that join a Transmission Organization would be eligible to apply to recover prudently-incurred costs associated with joining the Transmission Organization, either through rates charged by transmitting utilities or electric utilities or through transmission rates charged by the Transmission Organization that provides

[123] Id. P 326. Transmission Organization is defined as "a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities." Id. P 328.

services to such utilities.[124] Furthermore, the Commission stated that based on its interpretation of section 219, eligibility for this incentive flows to an entity that "joins" a Transmission Organization and is not tied to when the entity joined. Therefore, the Commission clarified that entities that have already joined, and that remain members of, an RTO, ISO, or other Commission-approved Transmission Organization, are eligible to receive this incentive.[125] However, as the Commission noted, any public utility receiving an incentive ROE for joining a Transmission Organization but withdraws from such organization is no longer eligible for the ROE incentive.

1. Rehearing Requests

80. Petitioners contend that public utilities should not be eligible for the Transmission Organization incentive if the public utilities are already members because the payment would neither induce new construction nor provide any new benefit to the customer paying the incentive rate.[126] They argue that the Final Rule's determination that incentives may go to entities that are already members of a Transmission Organization is contrary to court and Commission precedent interpreting incentive rates as forward-

[124] Id. P 329.

[125] Id. P 331.

[126] TDU Systems at 43; APPA/NRECA at 31-32, citing Southern California Edison Company, 114 FERC ¶ 61,018, at P 16 (2005) ("The rationale for this incentive is to encourage transmission owners to turn over the operational control of their transmission facilities to a regional transmission organization; therefore, it does not apply to transmission owners who have already done so, as they need no inducement to take such action")(Southern California Edison).

looking inducements, not a reward for past behavior.[127] The California Commission claims that the Final Rule's interpretation of section 219 exceeds the Commission's authority by creating an incentive that is broader than specified in the FPA.[128] Furthermore, TDU Systems assert that many public utilities have already joined ISO or RTOs without ROE incentives and have benefited from such membership. Those public utilities that have not joined have chosen not to do so because their business interests would not be advanced by a reduction in transmission barriers and constraints. Therefore, they argue that "recalcitrant utilities" should not be awarded windfall profits for holding out on participating in Transmission Organizations because such action would only amount to rewarding the exercise of market power.[129]

81. Furthermore, the California Commission states that an incentive for utilities that have already joined a Transmission Organization and are planning to build transmission facilities provides no balancing of the consumer interests and represents an unjust windfall.[130] By continuing its membership in an ISO/RTO, a transmission company will not incur any additional risks and will still remain a monopoly. The California

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[127] E.g., APPA/NRECA at 32; SMUD at 3-7; TDU Systems at 43. The California Commission argues that the courts have not permitted ROE adders for past conduct. California Commission at 18-19, citing Maine PUC v. FERC, 454 F.3d 278 (2006) and Allegheny Power Systems Operating Co., 111 FERC ¶ 61,308 (2005).

[128] California Commission at 14-15.

[129] TDU Systems at 42.

[130] California Commission at 16.

Commission and TDU Systems argue that the Commission did not provide any evidence that current RTO/ISO members may leave a Transmission Organization without the incentive of higher ROEs and therefore such a conclusion constitutes unreasonable, unlawful decision making.[131] APPA/NRECA assert that if a member leaves the Transmission Organization, the Commission can simply deny that utility a rate incentive.[132] Further, SMUD notes that there is no assurance that members will be permitted to leave since such a decision is subject to Commission review, and expresses concern that extending incentives to existing members of a Transmission Organization for not leaving may discourage parties legitimately dissatisfied with the Transmission Organization's performance and thereby make these organizations less accountable.[133] Finally, APPA/NRECA argue that the Commission's statement that it would be unduly discriminatory not to award all members of a Transmission Organization an incentive ROE has no basis because nothing in the FPA forbids different rates if these arrangements are necessary to carry out the provisions of the FPA and to serve the regulatory purposes contemplated by Congress.[134].

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[131] Id. P 17-18; TDU Systems at 43.

[132] APPA/NRECA assert that the Commission rejected such a remedy without a reasoned explanation in the Final Rule. APPA/NRECA at 32.

[133] SMUD at 3-7.

[134] APPA/NRECA at 33.

82. TDU Systems request clarification that the Commission will not consider single company entities as Transmission Organizations. They state that to ensure new transmission investment serves regional markets, a "collaborative [and] open regional planning process" is necessary. Therefore, TDU Systems claim that only entities that provide for, or participate in, regional planning that spans a number of public utility transmission systems should be eligible for incentives.[135]

83. TDU Systems recommend a reduction, i.e. negative 50 basis point penalty, in the authorized ROE for public utilities that withdraw from Transmission Organizations within the first five to ten years of participation to recognize the costs paid by consumers in anticipation of long-term savings. TDU Systems also argue that the incentive should not be allowed for public utilities ordered to join Transmission Organizations by statute, merger conditions or other regulatory requirements because there is no nexus between the incentive rates and demonstrated consumer benefits.[136] Finally, SMUD argues that the Final Rule offered no explanation for providing an incentive for utilities that are required to join Transmission Organizations as a merger condition.[137]

84. MISO TOs state that the Final Rule was unclear on the mechanics of requesting incentives by RTO members and request clarification that transmission owners may seek

[135] TDU Systems at 41-42.

[136] Id. at 42-43.

[137] SMUD at 7.

this incentive without opening up a Commission-accepted ROE or additional rates or formulas.[138] Specifically, they state that the Commission did not clarify that such a single-issue filing will not open up the already Commission-accepted ROE.

85. Finally, APPA/NRECA argues that the Final Rule does not comply with section 219(c) to provide incentives to each transmitting utility or electric utility that joins a Transmission Organization because it disregards incentives to non-jurisdictional utilities.[139] The Commission reasoning that it does not have jurisdiction to provide incentives for non-public utilities joining Transmission Organizations is unjustified when it has asserted jurisdiction in other proceedings.[140] APPA/NRECA recommend the Commission to consider incentives for non-public utilities such as assurances that these entities will fully recover all their costs of joining and participating in the Transmission Organization.

2. Commission Determination

86. We affirm the finding in the Final Rule that the incentive applies to all utilities joining transmission organizations, irrespective of the date they join, based on a reading of section 219 in its entirety. Section 219 specifically provides that "the Commission

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[138] MISO TOs at 2-3.

[139] APPA/NRECA at 53-54.

[140] Id. P 54, citing City of Vernon, California and CAISO, Opinion No. 479, 111 FERC ¶ 61,092, reh'g granted in part and denied in part, 112 FERC ¶ 61,207 (2005), reh'g denied, 115 FERC ¶ 61,297 (2006).

shall . . . provide for incentives to each transmitting utility or electric utility that joins a Transmission Organization." The stated purpose of section 219 is to provide incentive-based rate treatments that benefit consumers by ensuring reliability and reducing the cost of delivered power. We consider an inducement for utilities to join, and remain in, Transmission Organizations to be entirely consistent with those purposes. The consumer benefits, including reliability and cost benefits, provided by Transmission Organizations are well documented,[141] and the best way to ensure those benefits are spread to as many consumers as possible is to provide an incentive that is widely available to member utilities of Transmission Organizations and is effective for the entire duration of a utility's membership in the Transmission Organization. To limit the incentive to only utilities yet to join Transmission Organizations offers no inducement to stay in these

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[141] In Order No. 2000, in which the Commission's goal was to promote efficiency in wholesale electricity markets and to ensure that electricity consumers pay the lowest price possible for reliable service, the Commission stated that:

> These benefits [of RTOs] will include: increased efficiency through regional transmission pricing and the elimination of rate pancaking; improved congestion management; more accurate estimates of ATC; more effective management of parallel path flows; more efficient planning for transmission and generation investments; increased coordination among state regulatory agencies; reduced transaction costs; facilitation of the success of state retail access programs; facilitation of the development of environmentally preferred generation in states with retail access programs; improved grid reliability; and fewer opportunities for discriminatory transmission practices. All of these improvements to the efficiencies in the transmission grid will help improve power market performance, which will ultimately result in lower prices to the Nation's electricity consumers.

Order No. 2000, FERC Stats. & Regs. ¶ 31,089 at 31,024.

organizations for members with the option to withdraw, and hence risks reducing Transmission Organization membership and its attendant benefits to consumers. Because the incentive is applicable to utilities that join Transmission Organizations and is consistent with the requirements of section 219 of the FPA, the incentive complies with EPAct 2005 and the FPA.[142]

87. We consider the claim of APPA/NRECA that the incentive is inappropriate because it does not induce construction to be misplaced. Section 219(c), applicable to the Transmission Organization incentive, is separate from the construction incentives in subsection (b), and therefore was not intended to directly encourage construction.[143] However, we note that regional transmission organizations provide a platform for regional planning and cost allocation associated with transmission expansion and

[142] In light of our determination here, we reverse the policy adopted in our decision in Southern California Edison. Our decision in Southern California Edison failed to recognize that incentives are equally important in inducing utilities to join and remain in Transmission Organizations. Southern California Edison Co., 114 FERC ¶ 61,018, at P 16 (2005).

[143] We note that a more accurate interpretation of section 219(c) must recognize that an important component of section 219(c) is ensuring cost recovery, and therefore this section differs from the rest of section 219 that only address incentive-based rate treatments. We note that the Midwest ISO tariff provisions governing pass-through of transmission costs are consistent with this section, and this section would provide the basis for approval of pass-through of costs in other ISOs.

planning[144] and therefore can help support the identification and construction of transmission needed to ensure reliability and to reduce congestion.

88. We will not specify a particular method for establishing the appropriate ROE for entities that join and/or continue to be a member of an ISO, RTO, or other Commission-approved Transmission Organization in this generic proceeding. For example, the mechanics of setting an incentive ROE is an issue best addressed in a proceeding evaluating the Transmission Organization incentive for transmission owners that belong to the particular Transmission Organization. We recognize that the issue was remanded to the Commission with respect to Midwest ISO.[145] In the order on remand, the Commission observed that Midwest ISO or the MISO TOs can make a filing under section 205 to include an incentive adder.[146]

89. We affirm the Final Rule finding that this incentive applies to public utilities, as required by section 219, and therefore does not apply to non-public utilities and that non-

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[144] PJM Interconnection, L.L.C., 117 FERC ¶ 61,218 (2006); Midwest Independent Transmission System Operator, Inc., 114 FERC ¶ 61,106 (2006), order denying reh'g, 117 FERC ¶61,241, (2006); Midwest Independent Transmission System Operator, Inc., et al., 113 FERC ¶ 61,194 (2005); Midwest Independent Transmission System Operator, Inc., 109 FERC ¶ 61,168, order granting clarification, 109 FERC ¶ 61,243 (2004), reh'g pending.

[145] Midwest Independent Transmission System Operator, Inc., 100 FERC ¶ 61,292 (2002), order on reh'g, 102 FERC ¶ 61,143 (2003), order on remand, 106 FERC ¶ 61,302 (2004), aff'd in part and reversed in part, 397 F.3d 1004 (D.C. Cir. 2005).

[146] Midwest Independent Transmission System Operator, Inc., 111 FERC ¶ 61,355, at P 5 (2005).

public utilities may be permitted incentive-based rate treatments under section 211(a) of the FPA.

90. We will not make determinations on acceptable Transmission Organization structures and affiliations in this proceeding. The Commission will consider applications to form Transmission Organizations, based on the requirements of § 35.35(b), and make its determinations on the facts and circumstances of each filing.

I. Hypothetical Capital Structure

91. In the Final Rule, the Commission found that hypothetical capital structures can be an effective tool available to public utilities to foster transmission investment in appropriate circumstances. The Commission stated that it has allowed the use of hypothetical structures to improve access to capital markets for transmission investment and for specific projects when shown to be necessary for project financing.[147] To encourage the development of new transmission investment, the Commission noted that it will evaluate each proposal on a case-by-case basis and will not prescribe specific criteria or set target debt/equity ratios for evaluating hypothetical capital structures. As with other incentives, the applicant is required to demonstrate the required nexus between its proposed incentive and the facts of its particular case.[148]

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[147] The Commission noted that American Transmission and Trans-Elect are examples of the use of hypothetical capital structure to foster the development of transmission investment. Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 131.

[148] Id. P 133.

1. Rehearing Requests

92. The California Commission considers the hypothetical capital structure incentive-based rate treatment unnecessary for regulated utilities. According to the California Commission, when a company increases its actual debt ratio to a level higher than its optimal capital structure, the company will expose itself to financial risks at the expense of ratepayers, or will unnecessarily increase ratepayer costs. The California Commission also faults the Commission for not mandating the degree of rigorous scrutiny necessary for all cases before they are approved.[149] TDU Systems urge the Commission to adhere to Allegheny Power precedent that rejected hypothetical capital structures unless the utility's actual capital structure was so far out of line with the market-driven capital structures of representative proxy companies so as to be anomalous.[150]

2. Commission Determination

93. We repeat our finding in the Final Rule that hypothetical capital structures can be an appropriate ratemaking tool for fostering new transmission in certain relatively narrow circumstances. Historically, those circumstances have been somewhat unique, such as consortiums that require a special capital structure or projects that need project financing. As with other incentive ratemaking treatments, the Commission will require any applicant to demonstrate the required nexus between the need for a hypothetical capital

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[149] California Commission at 11-14.

[150] TDU Systems at 35-36, citing Allegheny Power Co. 103 FERC ¶ 63,001, at P 28 (2003), aff'd, 106 FERC ¶ 61,241, at P 27 (2004) (Allegheny Power).

structure and the proposed investment project. We would not normally expect traditional regulated utilities to propose incentives based on hypothetical capital structures (as was suggested by the California Commission) and we note that the Commission and state commissions have the ability to prevent any regulated company from increasing its debt ratio to a level that unnecessarily exposes wholesale or retail customers to unnecessary risk.

J. Single-Issue Ratemaking

94. The Commission concluded in the Final Rule that single-issue ratemaking can provide a significant incentive for new investment in transmission infrastructure because it can provide assurance that the decision to construct new infrastructure is evaluated on the basis of the risks and returns of that decision, rather than the additional uncertainty associated with re-opening the applicant's entire base rates to review and litigation.[151] The Commission stated that single-issue ratemaking applicants are only required to address cost and rate issues associated with the investment in the section 205 proceeding to approve rates. The applicant, however, is still required to fully develop and support any transmission rate design to recover the costs of a particular transmission system facility or upgrade, including cost allocation and rate design.[152] Further, the Commission noted that each application will be evaluated by balancing the need for new

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[151] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 191.

[152] Id. P 192.

infrastructure, and the importance of permitting single-issue ratemaking in support of that infrastructure, with the concerns over whether a specific mechanism is required to re-open existing rates or whether the traditional complaint processes are sufficient for that purpose.[153]

1. Rehearing Requests

95. Petitioners claim that single-issue ratemaking, as described in the Final Rule fails to balance shareholders' and consumers' interests and permits transmission owners to earn an unjust and unreasonable return on their overall transmission assets. They also assert that the Commission ignored its long-standing policy of rejecting single-issue ratemaking based on precedent that shows that single-issue ratemaking can lead to transmission providers earning super-normal returns while using single-issue rate filings to shield that fact from Commission scrutiny.[154] They argue that the Final Rule allows public utilities to increase their transmission rates on a piecemeal basis without providing procedures, short of section 206 complaints, to ensure that the public utility's steadily increasing rates do not become unlawful. They also contend that the Commission failed

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[153] Id.

[154] APPA/NRECA argue that, if a public utility has experienced load growth but has not invested in new transmission facilities, the public utility will have a strong disincentive not to file a section 205 rate case, because it will be earning a high rate of return on its highly depreciated rate base. They further assert that it has been their members' general experience that when public utility transmission providers believe they are undercollecting their transmission revenue requirements, they are quick to address the situation through a section 205 filing. APPA/NRECA at 41.

to consider reasonable alternatives such as a mandatory full transmission rate case every three years or allowing utilities to use formula rates that ensure a balance between risks borne by shareholders and ratepayers.[155]

96. Xcel states that the Final Rule anticipates the possibility of placing the applicant at risk for being ordered to file a section 205 rate case for its existing investments and contend that this potential risk will have the practical effect of discouraging limited section 205 incentive proposals. Accordingly, Xcel recommends that the Final Rule be modified so that it can achieve its stated purpose of providing assurance that the decision to construct new infrastructure is evaluated on the basis of the risks and returns of that decision, rather than the additional uncertainty associated with re-opening the applicant's entire base rates to review and litigation.[156] According to Xcel, to the extent the Commission believes the new single-issue rate must be harmonized with existing rates, the burden of proof should remain on the Commission, or the utility's customers, to show the existing filed rates are unjust and unreasonable and not shift the burden to the public utility.[157]

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[155] Id. at 40-43; TDU Systems at 21-23.

[156] Xcel at 4-5.

[157] Id. at 5.

2. Commission Determination

97. The Final Rule recognized that requiring transmission owners to open up their existing rates for review and litigation anytime they sought recovery of costs associated with a new transmission project could discourage new investment. Accordingly, the Final Rule permits an applicant to propose transmission rates associated with a particular project without proposing any changes to its existing transmission rates under section 205. We disagree with TDU Systems and APPA/NRECA that single-issue ratemaking will permit transmission owners to earn an unjust and unreasonable return on their overall transmission investment and we specifically committed that the Commission would consider the need to combine or reconcile any project-specific transmission rate proposal with any existing transmission rate, where necessary.

98. Indeed, the Final Rule specifies that the Commission may require the applicant to file a full rate case for existing transmission rates when evaluating a single-issue rate application, and therefore provides a procedure for additional rate review. However, we agree with Xcel that further clarification is necessary.[158] As indicated in the Final Rule, applicants for single-issue ratemaking are only required to address cost and rate issues associated with the new investment and therefore are not obligated to justify the

[158] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 192.

reasonableness of unchanged rates.[159] As PSC of N.Y. and Winnfield make clear, if intervenors or the Commission seek to challenge the applications beyond the limited issues raised in their applications, the intervenors or the Commission bear the burden of proof under section 206 in establishing that the existing, unchanged components of the rate are unjust and unreasonable. We further clarify that Commission review of the single-rate application will not be delayed in the event a separate section 206 investigation is initiated, thereby ensuring that new investments are not impeded because of existing-system rate issues.[160]

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[159] Public Service Comm'n of New York v. FERC, 642 F.2d 1335 (D.C. Cir. 1980)("we cannot accept the proposition that because a company files for higher rates, it bears the burden of proof on those portions of its filing that represent no departure from the status quo. . . . The emphasis is on making the petitioner justify the changes in rates, not the constant elements") (PSC of N.Y.); City of Winnfield, La. v. FERC, 744 F.2d 871 (D.C. Cir. 1984) ("The statutory obligation of the utility . . . is not to prove the continued reasonableness of unchanged rates or unchanged attributes of its rate structure") (Winnfield).

[160] This clarification is also consistent with Commission precedent:

> Protesters object to this option because of a concern that it may permit certain transmission owners to continue to overrecover their cost-of-service. However, this option provides just and reasonable cost recovery for the RTEP upgrades, and provide the necessary incentive for TOs to complete quickly the construction of RTEP projects that are essential to the efficient operation of PJM. As we said in the NYISO proceeding, if a concern arises regarding over-recovery of transmission costs, such parties are free to seek relief by filing a complaint with the Commission pursuant to section 206 of the FPA

(continued)

99. Based on the precedent cited above, we disagree with the conclusion that acceptance of single-issue rate filings would represent a dramatic shift in the historic balance between interests, and we therefore see no need to require additional consumer protections such as mandatory rate cases.

K. Public Power

100. In the Final Rule, the Commission noted that ratemaking incentives are generally not directly available to non-jurisdictional entities, i.e. public power entities, because they do not file their rates with the Commission.[161] However, the Commission recognized that public power participation can play an important role in the expansion of the transmission system and stated that public power participation in new transmission projects are encouraged. The Commission stated that the Commission will review appropriate requests for incentive ratemaking for investment in new transmission projects when public power participates with jurisdictional entities as part of a proposal for incentives for a particular joint project.[162]

Allegheny Power System Operating Co., 111 FERC ¶ 61,308, at P 46 (2005), order on reh'g and clarification, 115 FERC ¶ 61,156 (2006).

[161] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 354.

[162] Id. The Commission did not require a consortium approach that includes public power and other entities for new investment because it would be more appropriate for applicants to fashion proposals tailored to the specific circumstances and needs of a particular project. Id. P 356-57.

1. Rehearing Requests

101. TAPS requests the Commission to clarify that any approved incentive will be equally available to all owners of facilities that are found to merit incentives, regardless of the entity's form or business model and that the Commission will look with disfavor on incentive rate treatment applications by vertically-integrated utilities that exclude other utilities from co-owning a facility located in their common footprint.[163] TAPS contends that it is unduly discriminatory to allow large utilities to veto transmission incentives by refusing to participate in inclusive ownership arrangements. TDU Systems request the Commission to clarify that the option to participate in planning, financing and construction of new investment belongs to the public power system and that public utilities should not be allowed to use the availability of this option to avoid their obligation to construct needed network upgrades. TDU Systems urge the Commission to reconsider its determination that the Commission will not require public power or other joint participation in a transmission project in order for investment in a project to be eligible for incentives. They assert that conditioning a grant of any incentive rate treatments upon a robust, collaborative and open joint and regional planning process with all LSEs in the region and mandating compensation or credits for public power systems transmission facilities would better promote the Commission's goal under section 219.[164]

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[163] TAPS at 22.

[164] TDU Systems at 34-35.

Similarly, APPA/NRECA state that public power participation ensures that the lowest cost facilities are built, provide cash flow, and reduce uncertainty, thereby reducing the overall need for incentive rate treatments.[165] NECOE and APPA/NRECA also argue that public utilities should be required to offer joint ownership opportunities as a condition to receiving incentives. NECOE asserts that merely encouraging transmission owners to seek participation by public power has not worked in New England, thereby denying ratepayers the low cost benefits of public power. NECOE further contends that the exclusion of non-transmission owner investment from network upgrades violates Order No. 2000's open-architecture principles.[166] At a minimum, NECOE recommends that the Commission should require incentive applicants to state whether they have sought potential LSE co-investors, including public and consumer-owned utilities and where co-investors were sought but not permitted to participate, the proponent of an incentive should be required to explain why this was the case.[167]

2. Commission Determination

102. The Final Rule determined that the Commission would not condition recovery of incentives on the type of business structure and stated that the Commission will entertain appropriate requests for incentive ratemaking for investment in new transmission projects

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[165] APPA/NRECA at 51.

[166] NECOE at 9, citing Carolina Power and Light Cos., 95 FERC ¶ 61,282 at 61,995 (2001).

[167] NECOE at 5.

when public power participates as part of a proposal for incentives for a particular joint project.[168] While the Commission encourages public power participation, we will not require such participation as a condition of any proposed incentive rate treatment. As we state elsewhere in this order, the Commission cannot compel investment or certain types of investment. Our focus in this rule is to provide incentives that will facilitate voluntary investments by utilities. However, the Commission will look favorably on an incentive request that includes public power joint ownership. A wide variety of entities, such as merchant companies, private equity participants, and pool administrators can potentially build transmission infrastructure. In the context of a rule to provide rate incentives for the construction of new transmission and to encourage deployment of technologies to increase the capacity and efficiency of existing transmission facilities, we do not believe that mandating an opportunity for public power participation is necessary nor do we believe that failure to do so would be unduly discriminatory. However, we note that the Commission has initiated a rulemaking in Docket Nos. RM05-17-000 and RM05-25-000 to investigate necessary reforms to its existing pro forma OATT.[169] Among the reforms under consideration is to require all jurisdictional public utilities to establish regional transmission planning open to all participants in a region – including public entities. We believe that the OATT reform rulemaking is a more appropriate forum to consider any

[168] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 354.

[169] See OATT Reform NOPR, supra note 63.

issues or allegations regarding undue discrimination with regard to public power participation in transmission expansion decisions. Accordingly, we will not restrict eligibility for incentive rate treatment to projects that allow public power participation.

L. Other Issues

103. Parties request rehearing on a number of other issues discussed below.

1. Recovery of Costs of Abandoned Facilities

104. In the Final Rule, the Commission allowed applicants to seek recovery of 100 percent of prudently-incurred costs associated with abandoned transmission projects due to factors beyond the control of the public utility. The purpose of the incentive was to reduce the risk associated with potential upgrades or other improvements to the transmission system.

105. TDU Systems assert that the Commission should clarify that it would allow prudently incurred abandoned plant costs under limited circumstances. They contend that applicants for the incentive rate treatment that allows recovery of prudently-incurred abandoned plant costs should be required to demonstrate that, as a precondition to receiving the incentive, they will suffer cash flow problems if such a recovery was not allowed.[170] APPA/NRECA argue that the Commission should allow the incentive of abandoned cost recovery only on the condition that the public utility has engaged in open, regional transmission planning process to ensure some balance between the interests of

[170] TDU Systems at 38.

shareholders and ratepayers. They claim that the Commission wrongly relied on its granting of incentive rate treatment to American Transmission Company as a basis for this incentive without recognizing that the project was the result of joint planning.[171] Therefore, they assert that the Commission should not ask customers to pay for abandoned projects that they never had an opportunity to consider in the first instance.

106. We decline to specify any particular demonstration that an applicant must make to justify recovery of abandoned plant cost beyond the required nexus test described earlier. Also, as discussed in the prior section on public power participation, we do not intend to mandate public power participation as a pre-requisite for any particular transmission rate treatment in this rule – including recovery of abandoned plant costs. We note that in a recent case involving incentives,[172] the Commission expressly conditioned its approval of incentives (including a request for recovery of costs associated with any abandonment of the project) upon the project being included in the PJM regional transmission expansion plan.[173] For these reasons, we deny rehearing on this issue.

107. According to TDU Systems, the Commission must ensure that there is no double recovery of costs in instances in which other incentives are allowed for an abandoned

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[171] APPA/NRECA, 44-45. See Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 1, 116, 122, 131; American Transmission Co., LLC, 105 FERC ¶ 61,388 (2003).

[172] Allegheny Energy, Inc., 116 FERC ¶ 61,059 (2006), reh'g pending.

[173] American Electric Power Service Corp., 116 FERC ¶ 61,059 (2006), reh'g pending.

project. In the event the applicant receives the ROE incentive and the abandoned plant incentive rate treatment, TDU Systems argue there should be an offset of the rate impacts of these incentives to avoid over-recovery of costs so that the incentive can be provided at the least reasonable cost to consumers.[174] As described earlier in this order, we intend to evaluate any incentives requested as a package. To the extent that certain requested rate treatments have the effect of lowering the risk of a particular project, the Commission will take that into account in establishing an appropriate equity return for the project.

2. Prudently Incurred Costs

108. MISO TOs request clarification that limited section 205 filings are permissible for the recovery of costs of prudently-incurred costs necessary to comply with mandatory reliability standards in section 215.[175] MISO TOs argue that these costs may be imposed on transmission owners pursuant to statutory requirements and that without this clarification, they may be subject to extensive and expensive litigated cases, thereby discouraging utilities from recovering these costs that Congress authorized them to recover.

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[174] TDU Systems at 38.

[175] MISO TOs at 4-5.

109. We agree that rapid processing of the recovery of mandatory reliability costs will facilitate more timely investment in these important projects. Therefore, we clarify that applicants may file to recover these costs in limited section 205 filings.

3. Regional Planning

110. Parties contend that any public utility seeking incentive rates for its new transmission project should be required to demonstrate that the project was formulated through an open, regional planning process. Industrial Consumers assert that conditioning the granting of incentives upon the inclusion of a proposed transmission project in a regional planning process is critical to satisfying section 219's requirements to demonstrate customer benefit and promote economically efficient transmission. They claim that a coordinated regional planning process that considers the relative costs and benefits of multiple projects provides an optimal forum for determining least-cost solutions and avoiding unnecessary duplication of expenditures.[176] Similarly, NARUC and TAPS argue that no incentive should be available for projects that are to be sited in regions that plan regionally but which bypass the regional planning processes, noting that the Commission is proposing to require all jurisdictional public utilities to engage in regional planning in other Commission proceedings.[177] Further, TDU Systems argue that nothing in section 219 suggests that the Commission may not impose a regional planning

[176] Industrial Consumers at 11.

[177] NARUC at 6; TAPS at 7.

requirement and that making regional planning process a threshold requirement for incentive applications would be congruent with the mandate of section 219 to promote reliable and economically efficient transmission and generation of electricity.[178] APPA/NRECA also contend that the Commission has broad discretion in deciding particular incentives and that a regional planning requirement would harmonize section 219 with the objectives of section 217(b) to facilitate the planning and expansion of transmission facilities to meet the reasonable needs of LSEs. They also argue that the imposition of regional planning as a threshold requirement for incentive applicants is required by the mandate of section 219.[179]

111. The Final Rule grants a rebuttable presumption that projects resulting from regional planning qualify for incentive rate treatments, and we affirm that finding as discussed above. We will not, however, limit incentive rate treatments to projects that result from regional planning processes. While the Commission agrees that there are substantial benefits to be derived from regional planning, there may be transmission projects that arise outside of the context of a regional plan that help to ensure reliability or reduce the costs of delivered power and which deserve incentive rate treatment. Although the Commission has proposed to require regional planning as part of its OATT

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[178] TDU Systems at 9-10.

[179] APPA/NRECA at 16-19.

reform effort,[180] we note that many utilities are in regions in which no formal regional planning process exists at this time. However, as we stated in the Final Rule, and as modified by this order, projects are not entitled to a rebuttable presumption if they have not gone through a regional planning process, or have not received construction approval from an appropriate state commission or siting authority.[181] Applicants seeking incentives for such projects must independently demonstrate that the project will maintain reliability or reduce congestion.

4. <u>CWIP</u>

112. Because the long lead times required to plan and construct new transmission can negatively affect cash flow and the ability of a utility to attract capital at reasonable prices, the Final Rule allows public utilities to propose including 100 percent CWIP in rate base and expensing pre-commercial operations costs associated with new transmission investment.[182]

113. TDU Systems assert that the Commission should only allow 100 percent recovery CWIP and pre-commercial operations costs in the event the applicant shows that the transmission project will take more than four years to complete and that the applicant should have to demonstrate a regional need for the project to ensure that consumers

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[180] OATT Reform NOPR, <u>supra</u> note 63.

[181] In addition, and as modified by this order, an applicant may also rely upon the Commission's siting authority for meeting the requirements of section 219(a).

[182] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 115-22.

receive measurable benefits.[183] In addition, TDU Systems contend that, with respect to pre-commercial expenses, the Commission should: (1) ensure that these costs are not later capitalized in subsequent rate filings; and (2) limit the pre-commercial costs to be expensed to planning, siting and environmental costs so that costs that raise inter-generational equity concerns, such as the design and construction of facilities, are not included.[184]

114. We decline to establish any generic restrictions on the types of transmission projects or construction periods in order for a project to qualify for CWIP treatment under this rule. We leave to the applicant's discretion whether the construction project is of sufficient size to merit making a rate request to the Commission seeking to include CWIP in rate base or to expense pre-commercial operations costs. There may be reasons that justify seeking CWIP for projects with relatively short construction schedules e.g., a project may take only a few years to build but rates will not go into effect for a number of additional years because the project can not recover costs until other projects are built, and therefore CWIP recovery is justified. We clarify that the Commission's review process under section 205 will include a review to determine that the applicant does not double recover these costs. The Final Rule's definition of costs approved by the Commission to be recoverable as pre-certification costs in account 183, i.e., preliminary

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[183] TDU Systems at 9-10.

[184] Id. at 37.

survey and investigation costs,[185] does not include facility costs and therefore should not raise the inter-generational issues of concern to TDU Systems.

115. Finally, while CWIP and abandoned plant are characterized as "incentive-based rate treatments" in the Final Rule, we clarify that both of these rate mechanisms have been found previously to be just and reasonable under the Commission's authority pursuant to section 205.[186] More importantly, these are rate treatments which may be needed (and requested) in advance of a project being approved through a regional planning process or receiving any necessary siting approvals. To the extent an applicant demonstrates that the incentives sought (i.e., CWIP and abandoned plant) are tailored to address the demonstrable risks and challenges of the applicant, we will permit recovery of such prudently-incurred costs.

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[185] See Order No. 679, FERC Stats. & Regs. ¶31,222 at P 122 and n 82.

[186] See, e.g., American Electric Power Service Corp., 116 FERC ¶ 61,059, at P 55 (2006), reh'g pending (allowing recovery of 100 percent CWIP); Allegheny Energy, Inc., 116 FERC ¶ 61,058, at P 74 (2006), reh'g pending; American Transmission Co., L.L.C., 105 FERC ¶ 61,388, at P 27 (order establishing hearing and settlement judge procedures concerning, inter alia, the company's proposal for recovery of 100 percent CWIP), order dismissing reh'g and approving settlement, 107 FERC ¶ 61,117 (2004); Boston Edison Co., 109 FERC ¶ 61,300 (2004), order on reh'g, 111 FERC ¶ 61,266 (2005) (recovery of 50 percent CWIP); Southern California Edison Co., 112 FERC ¶ 61,014, at P 58-61, reh'g denied, 113 FERC ¶ 61,143, at P 9-15 (2005) (granting recovery of 100 percent of prudently incurred abandoned or cancelled plant costs); New England Power Co., Opinion No. 295, 42 FERC ¶ 61,016, at 61,068, 61,081-83 (recovery of 50 percent of prudently incurred cancelled plant costs), order on reh'g, 43 FERC ¶ 61,285 (1988); Public Service Co. of New Mexico, 75 FERC ¶ 61,266, at 61,859 (1996), order approving settlement, 87 FERC ¶ 61,040 (1999) (50 percent recovery of cancelled plant costs).

116. For example, where an applicant has satisfied our nexus requirement and has been granted authority to recover CWIP or abandoned plant, and subsequently the applicant's project is, for example, unable to obtain state or federal siting authority (and thus no showing is made with respect to ensuring reliability or reducing the cost of delivered power by reducing congestion because the applicant was relying upon those processes) we would not require refunds for the costs already prudently-incurred by the applicant. To require refunds in such circumstances would be contrary to our long-standing policy, which permits recovery of all prudently-incurred costs.[187]

5. Reporting Requirement: FERC-730

117. The Final Rule adopted an annual reporting requirement, FERC-730, for utilities that receive incentive rate treatment for specific transmission projects. The annual reporting requirement includes projections and related information that detail the level of transmission investment.[188]

118. TAPS argues that FERC-730's tracking of capital spending is misdirected by failing to identify how much consumers are spending as incentive rate treatments and

[187] The Commission "has applied the 'prudence' test to determine the recoverability of a utility's expenses. Under this test [a utility] is entitled to recover its costs from consumers if it acted 'prudently' in incurring those costs, or stated conversely, [a utility] may not recover its costs if those costs were incurred 'imprudently.'" Connecticut Yankee Atomic Power Co., 108 FERC ¶ 61,212, at P 42 (2004), quoting Violet v. FERC, 800 F.2d 280, 282 (1st Cir. 1986). See also, e.g., City of New Orleans v. FERC, 67 F.3d 947 (D.C. Cir. 1995) (citing Violet v. FERC)).

[188] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 367-76.

what they are getting in return. TAPS recommends that the Commission expand FERC-730 to include budgeted amounts by project on an annual basis, segregation of generation or distribution investments, a listing of which network service customers are predominantly paying for the project costs and the expected differential cost to consumers of each project's approved above-cost incentives.[189]

119. As the Commission explained in the Final Rule, the purpose of the FERC-730 reporting requirement is not to provide a quantitative measure of the consumer benefits that result from transmission infrastructure investments. In the proceeding approving incentives and recovery of the costs of incentives in rates, the Commission will determine whether proposed projects meet the requirements of section 219 and thereby provide consumer benefits and also set metrics to ensure those benefits are justified on an on-going basis. Therefore no further quantitative tracking of consumer benefits or expected differential costs to consumers is necessary. We repeat and affirm the Final Rule's statement that year-by-year capital spending estimates are not necessary for each individual project listed since the goal of the rule is not to ensure the achievement of annual capital spending targets but rather to ensure the overall projects are completed, and if not, the reasons for delay.

[189] TAPS at 29-31.

120. We will not limit the capital spending information requested from account numbers 350 through 359[190] to only investment in the transmission function, and exclude transmission investment in the generation or distribution functions. Capital investment in transmission facilities that interconnect generation facilities are ensuring reliability, and therefore are meeting the requirements of section 219. Accordingly, it is appropriate to include these amounts in transmission investment. Likewise, capital investment in lower voltage transmission facilities that are classified as part of the distribution function also accomplish the reliability and congestion reduction requirements of section 219 and therefore should be included in the survey of transmission investment. We see no need to require additional information on which customers pay for investment projects and the differential cost impact of the incentives. The purpose of FERC-730 is restricted to information on progress toward meeting the requirements of section 219. Customer allocation of cost responsibility is beyond the scope of that provision, and therefore that information does not need to be collected.

6. <u>Miscellaneous</u>

121. TDU Systems and APPA/NRECA argue that no incentives should be approved for projects that already have a binding commitment to build, including commitments under

[190] 18 CFR Part 101.

RTO arrangements, or for which applicants are obligated to build by statute, regulation or order.[191]

122. In general, we do not consider that contractual commitments or mandatory projects, such as section 215 reliability projects, disqualify a request for incentive-based rate treatment. Provided applicants are able to demonstrate they meet the requirements of section 219, including establishing the required nexus between the requested incentive and the investment, they may qualify for incentive-based rate treatments. A prior contractual commitment or statute may have a bearing on our nexus evaluation of individual applications.

123. EEI requests clarification that an applicant or group of applicants may propose rate incentives for a group of interrelated projects rather than for each single project individually, and thereby reduce the Commission burden.[192]

124. We clarify that applicants may propose incentives as a group, and note that such a group application process has been used by groups of transmission owners that are members of RTOs. With this clarification, we believe that revision of § 35.35(d) is unnecessary.

125. TAPS asserts that the Final Rule failed to explicitly provide that applicants' proposed incentives will be modified when doing so will advance the customer-

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[191] APPA/NRECA at 4; TAPS at 35.

[192] EEI at 6.

benefiting objectives of section 219. For example, TAPS argues that in order to modify the investment to which incentives will apply, an applicant may propose an incentive-worthy, congestion-reducing, new line packaged with mundane existing facility replacements that have already been committed to and do not advance the objectives of section 219.[193] In such a case, TAPS argues that the Commission should be able to modify the proposal to target incentives to the new line alone.

126. We do not consider this rulemaking to be the proper forum to assess whether a hypothetical application would meet the requirements of section 219 and Order No. 679. The Commission will determine whether incentive applications are just and reasonable based on the specific facts and circumstances of each proposal.

127. TDU Systems request clarification that metrics are required because certain statements in the Final Rule imply metrics are optional.[194] To the extent the use of metrics determines that a project does not provide the anticipated benefits, ratepayers should receive refunds based on the monetary value of the incentive, according to TDU Systems.

128. We clarify that applicants are required to propose metrics in their incentive applications. However, it is not the Commission's intention to approve incentive rate

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[193] TAPS at 12.

[194] See Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 36 ("an applicant may propose periodic progress assessments….").

treatments “subject to refund.” To the extent that a customer has a reason to believe that any rate that has been approved by the Commission is no longer just, reasonable, and not unduly discriminatory or preferential, they will need to file an appropriate complaint under section 206.

129. TAPS contends that the Commission is not statutorily free to rule out symmetrical, i.e. performance-based approaches to setting an appropriate return regardless of whether they are sponsored by incentive applicants or recommended with appropriate support by intervenors. TAPS states that section 219 expressly provides that incentive programs may be performance-based and has long been a foundation for Commission incentive rate policy.[195] SMUD asserts that the Commission failed to explain its departure from the 1992 Policy Statement that symmetry is an inherent part of all incentive ratemaking.[196]

130. The purpose of this rule is to provide incentive-based rate treatments that benefit consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. The primary focus of the rule is necessarily on investment. However, while the Final Rule declined to adopt generic performance-based ratemaking measures, we did encourage the industry to work on developing performance-based ratemaking proposals. While we agree that section 219 does not rule out symmetrical approaches to return, to the extent applicants or intervenors propose performance-based

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[195] TAPS at 28.

[196] SMUD at 9-10.

rate treatments under section 219, they must justify their proposals in terms of their capability to attract investment and either ensure reliability or reduce the cost of delivered power by reducing congestion.

131. TAPS asserts that the Commission cannot determine if an incentive will be non-discriminatory, as required under section 219(d), unless it ascertains what ratepayer classes are subject to paying for the incentive. TAPS also claims the Commission needs to consider whether an incentive request should be conditioned on geographically broadened cost spreading in order to determine whether the requested incentives can be better formulated to advance the consumer benefits of section 219. TAPS further argues that the Commission should state its willingness to consider in declaratory petition proceedings how costs will be allocated for the subject facilities and whether altering that treatment should be part of the incentive program.[197] TDU Systems assert that the Commission must require roll-in of new and existing rates to encourage investment.

132. We repeat the finding in the Final Rule that the section 205 proceedings addressing recovery of the costs of incentive-based rate treatments are the appropriate forum for determining whether the resulting rates are just, reasonable and non-discriminatory, and therefore are the appropriate proceedings to consider cost allocation and rate design issues.[198] The primary purpose of the declaratory petition proceeding is

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[197] TAPS at 17-18.

[198] E.g., Order No. 679, FERC Stats. & Regs. ¶ 31,622 at P 81.

to determine if the proposed incentives meet the requirements of section 219, and therefore cost allocation and rate design issues will not be considered. Finally, we consider rate design issues, such as roll-in of rates to beyond the scope of this proceeding, and therefore affirm the Final Rule's determination to not require roll-in of rates.[199]

133. Southern Companies assert that the Commission's routine imposition of a five-month suspension of rates is a disincentive to the construction of new transmission infrastructure, claiming that delaying the effective date of a rate change forces the utility to absorb costs associated with new facilities and reduces the utility ROE.[200]

134. The Commission addressed this concern in the Final Rule by stating that we will not revise our suspension policy in this proceeding. We affirm the Final Rule's finding that utilities should raise concerns with the Commission's suspension policy in our pre-filing process.

135. Energy Financing requests clarification that its proposed performance-based financing option for transmission investment is not excluded as an alternative method of achieving the Commission's and Congress' goal of encouraging more transmission investment, or in the alternative, it seeks rehearing arguing that alternative financing methodologies are viable vehicles to increase transmission investment, in lieu of or in

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[199] Id. P 192.

[200] Southern Companies at 19-20.

addition to the incentives identified in the Final Rule.[201] Energy Financing's proposal concerns how a project is financed rather than an incentive-based rate treatment. We do not consider it an alternative to the incentive-based rate treatments specified in § 35.35. Also, we can not make a determination as to whether the option will increase transmission investment because Energy Financing has not provided any information to indicate that its option is having the purported effect on investment. For these reasons, we deny rehearing on this issue.

136. Finally, the introductory text in § 35.35(d)(1) is revised to delete redundant language.

IV. Information Collection Statement

137. Order No. 679 contains information collection requirements for which the Commission obtained approval from the Office of Management and Budget (OMB). The OMB Control Number for this collection of information is 1902-0203. This order denies most rehearing requests, clarifies the provisions of Order No. 679, and grants rehearing on only three minor issues. This order does not make substantive modifications to the Commission's information collection requirements and, accordingly, OMB approval for this order is not necessary. However, the Commission will send a copy of this order to OMB for informational purposes.

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[201] Energy Financing at 4-5.

V. Document Availability

138. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, N.E., Room 2A, Washington D.C. 20426.

139. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

140. User assistance is available for eLibrary and the FERC's website during normal business hours from our Help line at (202)502-8222 or the Public Reference Room at (202) 502-8371 Press 0, TTY (202)502-8659. E-Mail the Public Reference Room at public.referenceroom@ferc.gov.

VI. Effective Date

141. Changes to Order No. 679 made in this order on rehearing will become effective on [insert 30 days after publication in the **Federal Register**].

<u>List of subjects in 18 CFR Part 35</u>
Electric power rates
Electric Utilities
Reporting and record keeping requirements

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.

In consideration of the foregoing, the Commission amends part 35 of Chapter I, Title 18, Code of Federal Regulations, as follows:

PART 35 – FILING OF RATE SCHEDULES AND TARIFFS

1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601-2645; 31 U.S.C. 9701; 42 U.S.C. 7101-7352.

2. Section 35.35 is amended as follows by:

a. Revising the third sentence in paragraph (d) introductory text ,

b. Revising paragraph (d)(1) introductory text;

c. Revising paragraph (i); and

d. Adding a new paragraph (j) to read as follows:

Subpart G – Transmission Infrastructure Investment Provisions

§ 35.35 Transmission infrastructure investment.

*** * * * ***

(d) Incentive-based rate treatments for transmission infrastructure investment. * * * The applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219, that the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project, and that resulting rates are just and reasonable.* * *

(1) For purposes of this paragraph (d), incentive-based rate treatment means any of the following:

* * * * *

(i) Rebuttable presumption. (1) The Commission will apply a rebuttable presumption that an applicant has demonstrated that its project is needed to ensure reliability or reduces the cost of delivered power by reducing congestion for:

(i) A transmission project that results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or

(ii) A project that has received construction approval from an appropriate state commission or state siting authority.

(2) To the extent these approval processes do not require that a project ensures reliability or reduce the cost of delivered power by reducing congestion, the applicant bears the burden of demonstrating that its project satisfies these criteria.

(j) Commission authorization to site electric transmission facilities in interstate commerce. If the Commission pursuant to its authority under section 216 of the Federal Power Act and its regulations thereunder has issued 1 or more permits for the construction or modification of transmission facilities in a national interest electric transmission corridor designated by the Secretary, such facilities shall be deemed to either ensure reliability or reduce the cost of delivered power by reducing congestion for purposes of section 219(a).

Note: The following appendix will not appear in the Code of Federal Regulations.

APPENDIX A

Requests for Rehearing

American Public Power Association and National Rural Electric Cooperative Association (together, APPA/NRECA)

Coalition of Midwest Transmission Customers, PJM Industrial Customer Coalition, NEPOOL Industrial Customer Coalition, Southeast Electricity Consumers Association, and Southwest Industrial Customer Coalition (collectively, Industrial Consumers)

Connecticut Department of Public Utility Control, the Massachusetts Municipal Wholesale Electric Company, the Connecticut Municipal Electric Energy Cooperative, the New Hampshire Electric Cooperative, the Maine Public Utility Commission, and the New England Conference of Public Utility Commissioners (collectively, New England Commissions)

Edison Electric Institute (EEI)

Energy Financing, Inc. (Energy Financing)

Midwest ISO Transmission Owners (MISO TOs)

National Association of Regulatory Utility Commissioners (NARUC)

New England Consumer-Owned Entities (NECOE)

Public Utilities Commission of the State of California (California Commission)

Sacramento Municipal Utility District (SMUD)

Southern California Edison Company (SoCal Edison)

Southern Company Services, Inc., on behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company (collectively, Southern Companies)

Transmission Access Policy Study Group (TAPS)

Transmission Dependent Utility Systems (TDU Systems)

Xcel Energy Services, Inc. (Xcel)

119 FERC ¶61,062
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Promoting Transmission Investment through Pricing Reform — Docket No. RM06-4-002

ORDER ON REHEARING

(Issued April 19, 2007)

1. This order addresses requests for rehearing and clarification of Order No. 679-A,[1] which reaffirmed in part and granted in part rehearing of the Final Rule on *Promoting Transmission Investment through Pricing Reform*.[2] Order Nos. 679 and 679-A amended Commission regulations to provide incentives for transmission infrastructure investment to help ensure the reliability of the bulk power transmission system in the United States or reduce the cost of delivered power to customers by reducing transmission congestion. As discussed below, we deny rehearing and grant clarification in part of Order No. 679-A.

I. Background

2. In 2005, Congress enacted section 1241 of the Energy Policy Act of 2005, which added a new section 219 to the Federal Power Act (FPA) to promote the operation, maintenance and enhancement of transmission infrastructure.[3] Pursuant to section 219, the Commission issued Order No. 679, which amended Commission regulations to establish incentive-based (including performance-based) rate treatments for the

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[1] *Promoting Transmission Investment through Pricing Reform*, Order No. 679-A, 72 Fed. Reg. 1152 (January 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2007) (Order No. 679-A).

[2] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 Fed. Reg. 43,294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006) (Order No. 679).

[3] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 315 and 1283 (2005).

transmission of electric energy in interstate commerce by public utilities for the purpose of benefiting consumers by ensuring reliability or reducing the cost of delivered power by reducing transmission congestion. In general, Order No. 679 identified ratemaking treatments available under section 219 and required each applicant to tailor its proposed incentives to the type of transmission investments being made and to demonstrate that its proposal meets the requirements of section 219.

3. Many entities sought rehearing of Order No. 679. In response, the Commission issued Order No. 679-A reaffirming its determinations in part and granting rehearing in part. In general, Order No. 679-A retained the rate treatments adopted in Order No. 679, but modified the way in which the rate treatments are applied.[4]

II. Requests for Rehearing

4. In response to Order No. 679-A, a number of parties submitted timely requests for rehearing and clarification: Transmission Access Policy Study Group (TAPS); American Public Power Association and National Rural Electric Cooperative Association (APPA/NRECA); Transmission Dependent Utility Systems (TDU Systems); Certain Midwest ISO Transmission Owners (Midwest ISO TOs); and FirstEnergy Service Company (FirstEnergy).

5. As discussed below, TAPS, APPA/NRECA and TDU Systems seek rehearing of Order No. 679-A's determination that the Commission would entertain a public utility's request to determine the public utility's rate of return on equity (ROE) for a particular project by declaratory order in advance of the public utility's filing of rates pursuant to section 205 of the FPA.[5] Midwest ISO TOs seek clarification with respect to Order No. 679-A's statement that reliability projects may only be eligible for incentives to the extent that such projects have special risks and challenges. FirstEnergy seeks clarification regarding the eligibility of a public utility member of a Regional Transmission Organization (RTO) for the Transmission Organization incentive.

III. Discussion

A. ROE Determination in a Declaratory Order

6. In Order No. 679, the Commission stated that it will allow, when justified, an incentive-based ROE for all public utilities (i.e., traditional public utilities and Transcos)

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[4] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 4-7.

[5] 16 U.S.C. § 824d (2000).

making new investments in transmission facilities that benefit consumers by ensuring reliability or reducing the cost of delivered power by reducing congestion.[6] In Order No. 679-A, the Commission recognized that the traditional ratemaking process may create uncertainty for investors.[7] Traditionally, an ROE determination occurs in a hearing convened to determine the justness and reasonableness of the costs of the investment for purposes of setting rates under section 205. Because such a hearing often occurs only after an investment decision is made and the facility is constructed, it may create uncertainty as to the ultimate return and thereby result in disincentives for new investment. Therefore, in Order No. 679-A, the Commission clarified the approach for reviewing ROE incentive requests and allowed an applicant seeking up-front certainty regarding the ROE it may receive to submit, by means of a request for declaratory order, a specific proposed ROE for its project.[8] The Commission noted that such declaratory order requests must include the appropriate support for the ROE, e.g., a discounted cash flow (DCF) analysis, and will have to meet the required nexus requirement.[9]

1. <u>Rehearing Requests</u>

7. APPA/NRECA and TDU Systems argue that the Commission erred in Order No. 679-A by allowing a public utility's ROE for a particular project to be determined by a declaratory order prior to the public utility's filing of rates pursuant to section 205 of the FPA, without reserving the Commission's authority to modify the ROE or other aspects of the resulting rates. They assert that without this reservation of authority, the Commission would not be able to ensure that the rates comply with the requirements of section 219 of the FPA, are not unduly discriminatory or preferential, and represent a "package of incentives [that] is tailored to address the demonstrable risks or challenges

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[6] Order No. 679, FERC Stats & Regs. ¶ 31,222 at P 91.

[7] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 69.

[8] *Id*. P 70. The Commission also noted that applicants may request in a petition for declaratory order, and may be eligible for, a specific, incentive ROE that is in the upper end of the zone of reasonableness. However, the Commission also stated that, "the fact that an up-front ROE determination is itself an incentive that tends to reduce risk will be taken into account in considering any such request." *Id.*

[9] *Id.*

faced by the applicant in undertaking the project."[10] TDU Systems also contend that customers would not have adequate opportunity to raise any discriminatory rate design issues before the Commission under the two-step process for ROE approval.[11]

8. Further, TAPS asserts that the Commission erred in Order No. 679-A because it clarified that applicants may secure an early ruling that a particular ROE is appropriate, while the issue as to who will pay the incentive may generally be deferred to a later stage. TAPS requests the Commission to confirm that before granting final approval to any incentive it will consider (a) whether such collection would be discriminatory as applied, and (b) whether the placement of payment responsibilities will undo the rational nexus between a project and its incentive. Such consideration should include consideration of pertinent facts, including who else will pay the incentive.[12] TAPS argues that absent such consideration, there can be no rational basis for the findings of non-discrimination and rational tailoring that both the regulatory text and FPA sections 205, 206, and 219 require.[13] TAPS also suggests that applicants who want early certainty about their

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[10] APPA/NRECA at 5-6; TDU Systems at 2-3. APPA/NRECA also cite a 2004 hearing order in which the Commission set for hearing an incentive rate proposal to apply an ROE adder to unbundled transmission customers but not bundled retail customers, noting its concerns about possible undue discrimination. *Midwest Independent Transmission System Operator, Inc. and Ameren Services Co.*, 109 FERC ¶ 61,167, at P 14 (2004). They contend that the declaratory order procedure adopted in Order No. 679-A could allow the Commission to approve a similar proposal without setting the discrimination issue for hearing.

[11] TDU Systems at 7-8.

[12] TAPS proffers an example of a transmission-dependent municipal system that seeks to join a consortium of investor-owned market participants in developing a transmission project, but is rebuffed. In that situation, TAPS contends that, as a matter of due process and reasoned decisionmaking, the excluded municipal system should be allowed to demonstrate that it would be unduly discriminatory to make it pay the higher return, even if that return level satisfied other relevant standards. TAPS also argues that where a project's costs are directly assigned to a customer (e.g., through participant funding), an above-average rate charged to that customer-funder would discourage the customer-funder from approving construction.

[13] TAPS at 4.

incentives in a declaratory order should have to give the Commission some early assurance about who will pay for those incentives.[14]

9. APPA/NRECA also offer an example of a utility that seeks and obtains an incentive ROE in a declaratory order, but seeks additional incentives such as construction work in progress and pre-commercial operations costs in a subsequent 205 rate filing. They express concern that if the Commission cannot change the ROE determined in the declaratory order, its options would be limited to approving or denying the additional incentives. They argue that the declaratory order should not preclude customers from arguing in the section 205 case that – in light of the additional, proposed, risk-lowering incentives for the project – the incentive ROE is no longer tailored to the demonstrable risks or challenges faced by the applicant in undertaking the project.[15]

2. Commission Determination

10. The Commission denies rehearing. In Order No. 679, the Commission allowed applicants to seek incentives either in a request for declaratory order or a section 205 rate proceeding. In Order No. 679-A, the Commission affirmed that approach, adding that an applicant has two options when seeking an incentive ROE in a declaratory order proceeding. It may either seek a specific, proposed incentive ROE for its project within the upper end of the zone of reasonableness as determined, e.g., by a DCF analysis, if it can meet the required nexus requirement, or it may seek an incentive ROE generally within the upper end of the zone of reasonableness (in which case the Commission would determine in a subsequent hearing under section 205 where in the upper end the ROE would fall).[16]

11. The Commission also explained that an applicant is required to demonstrate that the total package of incentives it seeks is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project. If some of the incentives in the package reduce the risks of the project, that fact will be taken into account in any request for an enhanced ROE.

12. In response to the concerns raised by APPA/NRECA, we clarify that the declaratory order approach adopted in the Final Rule will in no way undermine the Commission's ability to ensure that all incentives sought by an applicant are tailored to

[14] *Id.* at 6.

[15] APPA/NRECA at 7.

[16] *See supra* note 8.

address the risks and challenges faced by that applicant and are consistent with section 219. If an applicant obtains a specific incentive ROE determination from the Commission in a declaratory order proceeding, and, in a later section 205 proceeding, seeks additional non-ROE incentives that were not proposed in the earlier declaratory order proceeding, the Commission will still be required to ensure that the total incentive package is tailored to the risks and challenges faced by the project when it evaluates section 205 filing. In this circumstance, customers would not be precluded from arguing that newly proposed incentives that might lower risks must be balanced against the previously granted incentive ROE. Depending upon the facts presented, the Commission may or may not grant the additional non-ROE incentives. Also, depending upon the facts, it is possible that an applicant would have valid reasons to voluntarily forgo the earlier granted ROE incentive if the Commission concluded that the non-ROE incentives were justified on a stand-alone basis but not in conjunction with the specific, incentive ROE granted previously in a declaratory order. As a result, no applicant will receive an incentive package that does not meet the standards of section 219, section 205, and the test adopted in Order Nos. 679 and 679-A. Though we encourage applicants to seek all requested incentives in the same proceeding (whether in a request for declaratory order or a section 205 filing), we do not require it. Additionally, where an applicant receives authority for an incentive rate in a declaratory order, but then proposes in a section 205 proceeding to apply that incentive ROE in a manner that may be unjust and unreasonable or unduly discriminatory or preferential, the Commission retains the authority to set the matter for hearing at that time.

13. Finally, the Commission has previously addressed TAPS' assertion that cost allocation decisions must be made before an incentive request may be considered. In response to TAPS' first request for rehearing on this point, we noted in Order No. 679-A that section 205 proceedings are the appropriate proceedings in which to consider cost allocation and rate design issues.[17] We reiterate that finding here.

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[17] "We repeat the finding in the Final Rule that the section 205 proceedings addressing recovery of the costs of incentive-based rate treatments are the appropriate forum for determining whether the resulting rates are just, reasonable and non-discriminatory, and therefore are the appropriate proceedings to consider cost allocation and rate design issues. The primary purpose of the declaratory petition proceeding is to determine if the proposed incentives meet the requirements of section 219, and therefore cost allocation and rate design issues will not be considered. Finally, we consider rate design issues, such as roll-in of rates to [be] beyond the scope of this proceeding, and

(continued)

B. Eligibility of Reliability Projects for Incentives

14. While Order No. 679 provided incentive-based ROEs, when justified, to all public utilities for new investments in transmission that benefit consumers by ensuring reliability or reducing the cost of delivered power by reducing congestion, the Commission noted that not every investment that increases reliability or reduces congestion will qualify for such an incentive.[18] The Commission stated that pursuant to section 219, its mandate is to encourage new investment and to strike the appropriate balance between the investor and consumer interests. In that respect the Commission, while stating that it will consider applications for ROE incentives for all projects, reaffirmed this finding, stating that the "most compelling case" for incentive-based ROEs are new projects with special risks or challenges, not routine investments made in the ordinary course of expanding the system to provide safe and reliable transmission service.[19]

15. Additionally, Order No. 679 granted a rebuttable presumption that projects resulting from regional planning qualify for incentive rate treatments. The Commission affirmed that finding in Order No. 679-A, but also stated that the incentive rate treatments are not limited to projects that result from regional planning process.[20] The Commission noted that there may be transmission projects that arise outside of the regional planning process that help to ensure reliability or reduce the costs of delivered power and thereby qualify for incentive rate treatment.

1. Request for Clarification

16. Midwest ISO TOs seek clarification of Order No. 679-A regarding the Commission's statement that reliability projects may only be eligible for incentives to the extent that such projects have special risks and challenges. They state that it is unclear how the Commission will implement this policy, as it has elsewhere established a rebuttable presumption that projects that are approved through a regional planning

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therefore affirm the Final Rule's determination to not require roll-in of rates." *See* Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 131-132, citing Order No. 679, FERC Stats & Regs. ¶ 31,222 at P 81.

[18] Order No. 679, FERC Stats & Regs. ¶ 31,222 at P 91, 94.

[19] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 60.

[20] *Id.* P 111.

process will be eligible for incentives.[21] They state that the Commission indicated that it may be less likely to grant an incentive for projects needed for routine reliability than those projects that present special risks or challenges.[22] Midwest ISO TOs state that the Commission does not define what it means by routine projects, what it would consider special risks or challenges, or explain how this will be implemented in the context of RTOs.

17. Midwest ISO TOs state that they support the Commission's policy to apply a rebuttable presumption to projects that result from a RTO planning process and are found to be necessary and appropriate for reliability purposes. However, they seek guidance to ensure that the necessary transmission facilities are constructed to promote and preserve reliability and that there is no disincentive provided to the construction of reliability projects. In that respect, they seek clarification that the Commission's statement regarding routine investment is not intended to disrupt or modify this rebuttable presumption.[23] Therefore, the Commission should clarify, in the context of an RTO planning process, what it means by the statement that reliability projects may only be eligible for incentives to the extent that such projects have special risks and challenges.

2. <u>Commission Determination</u>

18. We deny Midwest ISO TOs' request for clarification because these arguments were raised and resolved on rehearing of Order No. 679. In response to a request for rehearing by TAPS, we clarified in Order No. 679-A that the rebuttable presumption related to a regional planning process applies only to the threshold requirement under section 219 that an applicant demonstrate that a project is needed to ensure reliability or to reduce congestion. It does not apply to any other requirement in 18 C.F.R. § 35.35, such as the requirement that the applicant demonstrate the required nexus between the incentive sought and the investment being made. It is in the context of this latter demonstration – that there be a nexus – that we stated that routine investments may not qualify for an incentive-based ROE. Incentives for reliability projects will be based, on a case-by-case basis, on the challenges and risks of the particular reliability project, e.g., long-term, high-cost reliability projects with siting issues may justify a higher incentive than small scale, maintenance reliability projects that can be completed within a year. What the Commission finds to be a routine project, and what it would consider special

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[21] Midwest ISO TOs at 2.

[22] *Id.* at 3.

[23] *Id.* at 5.

risks or challenges, as well as how this will be implemented in the context of RTOs, will be determined on a case-by-case basis.

C. Eligibility of an RTO Member for the Transmission Organization Incentive

19. Order No. 679 provided that public utilities that join a Transmission Organization, including RTOs, are eligible to file for incentive rate treatment, in the form of a higher ROE. It also clarified that public utilities that are currently members of a Transmission Organization could apply for such incentive treatment.[24] The Commission affirmed that finding in Order No. 679-A, noting that the incentive applies to all utilities joining Transmission Organizations, irrespective of the date they join.[25] The Commission stated that an inducement for utilities to join, and remain in, Transmission Organization is consistent with the purpose of section 219, which is to provide incentive-based rate treatments that benefit consumers by ensuring reliability and reducing the cost of delivered power.[26] Among other things, the Commission also noted in Order No. 679-A that incentive ROEs will not apply to existing transmission rate base that has already been built because the purpose of section 219 is to attract investment in transmission.[27]

1. Request for Clarification

20. FirstEnergy requests the Commission to clarify that under Order Nos. 679 and 679-A, a public utility that is a member of an RTO is eligible to apply for higher ROE incentive rate treatment for all of its jurisdictional transmission facilities.[28] It requests clarification that the Transmission Organization ROE incentive is not tied to the construction of new transmission facilities. It asserts that section 219(c) states that the Commission must provide incentives to utilities that join a Transmission Organization, and that section is not tied to a requirement that such eligibility is only for new transmission facilities. According to FirstEnergy, the plain language of section 219(c), together with the policy goals expressed by the Commission in Order Nos. 679 and 679-A, establish an incentive for utilities that join Transmission Organizations that is

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[24] Order No. 679, FERC Stats & Regs. ¶ 31,222 at P 331.

[25] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 86.

[26] *Id.*

[27] *Id*. P 61.

[28] FirstEnergy at 1.

separate and apart from the incentive established for new transmission construction.[29] Therefore, FirstEnergy requests the Commission to clarify that a public utility member of an RTO is eligible for the Transmission Organization incentive as to all of its jurisdictional transmission facilities based on its participation in a Transmission Organization only and not on any requirement linked to its transmission construction program.

2. Commission Determination

21. FirstEnergy is correct that a public utility member of an RTO is eligible for the Transmission Organization incentive rate treatment as to all of its jurisdictional transmission facilities that have been turned over to the operational control of the Transmission Organization. This incentive is separate from incentives related to a utility's transmission construction program.[30] Therefore, we clarify that Transmission Organization ROE incentive is not tied to the construction of new transmission facilities.

The Commission orders:

(A) The requests for rehearing of Order No. 679-A are hereby denied, as discussed in the body of the order.

(B) The requests for clarification of Order No. 679-A are granted in part and denied in part, as discussed in the body of the order.

By the Commission.

(S E A L)

Philis J. Posey,
Deputy Secretary.

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[29] *Id.* at 4.

[30] *See* Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 87 ("Section 219(c), applicable to the Transmission Organization incentive, is separate from the construction incentives in subsection (b), and therefore was not intended to directly encourage construction.") (footnote omitted).

141 FERC ¶ 61,129
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Parts 2 and 35

[Docket No. RM11-26-000]

Promoting Transmission Investment Through Pricing Reform

(Issued November 15, 2012)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Policy Statement.

SUMMARY: The Commission issues this policy statement to provide guidance regarding its evaluation of applications for electric transmission incentives under section 219 of the Federal Power Act. In the six years since the Commission implemented section 219 by issuing Order No. 679, the Commission has acted on numerous applications for transmission incentives. The Commission has now determined it would be beneficial to provide additional guidance and clarity with respect to certain aspects of its transmission incentives policies under section 219 of the Federal Power Act and Order No. 679. In particular, the Commission: reframes its nexus test to focus more directly on the requirements of Order No. 679; expects applicants to take all reasonable steps to mitigate the risks of a project, including requesting those incentives designed to reduce the risk of a project, before seeking an incentive return on equity (ROE) based on a project's risks and challenges; provides general guidance that may inform applications for an incentive ROE based on a project's risks and challenges; and promotes additional transparency with respect to the impacts of the Commission's incentives policies. The

Commission finds that the additional guidance provided through this policy statement is necessary to encourage transmission infrastructure investment while maintaining just and reasonable rates, consistent with section 219 of the Federal Power Act. The Commission will apply this policy statement on a prospective basis to incentive applications received after the date of its issuance.

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141 FERC ¶ 61,129
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

Promoting Transmission Investment Through Pricing Reform | Docket No. RM11-26-000

POLICY STATEMENT

(Issued November 15, 2012)

1. The Commission issues this policy statement to provide guidance regarding its evaluation of applications for electric transmission incentives under section 219 of the Federal Power Act (FPA).[1] In the six years since the Commission implemented section 219 by issuing Order No. 679,[2] the Commission has acted on numerous applications for transmission incentives. The Commission has now determined it would be beneficial to provide additional guidance and clarity with respect to certain aspects of its transmission incentives policies under section 219 of the Federal Power Act and Order No. 679. In particular, the Commission: reframes the nexus test to focus more directly on the requirements of Order No. 679; expects applicants to take all reasonable steps to mitigate

[1] 16 U.S.C. § 824s (2006).

[2] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 FR 43294 (Jul. 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, 72 FR 1152 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236, *order on reh'g*, 119 FERC ¶ 61,062 (2007).

the risks of a project, including requesting those incentives designed to reduce the risk of a project, before seeking an incentive return on equity (ROE) based on a project's risks and challenges; provides general guidance that may inform applications for an incentive ROE based on a project's risks and challenges; and promotes additional transparency with respect to the impacts of the Commission's incentives policies. The Commission finds that the additional guidance provided through this policy statement is necessary to encourage transmission infrastructure investment while maintaining just and reasonable rates, consistent with section 219 of the FPA. The Commission will apply this policy statement on a prospective basis to incentive applications received after the date of its issuance.

I. Background

2. Section 1241 of the Energy Policy Act of 2005 added a new section 219 to the FPA. The Commission implemented section 219 by issuing Order No. 679, which established by rule incentive-based rate treatments for investment in electric transmission infrastructure for the purpose of benefiting consumers by ensuring reliability and reducing the cost of delivered power by reducing transmission congestion. Since the issuance of Order No. 679, the Commission has evaluated more than 85 applications representing over $60 billion in potential transmission investment.

3. On May 19, 2011, the Commission issued a notice of inquiry (NOI) seeking public comment regarding the scope and implementation of the Commission's incentives policies. The Commission received over 1,500 pages of comments reflecting a wide range of perspectives on the Commission's incentives policies. The Commission

appreciates the robust participation by the diverse group of commenters, and has carefully considered the comments received in formulating this policy statement. The Commission's issuance of this policy statement is driven by its experience applying its incentives policies to individual incentive applications and comments received in response to the NOI.

II. <u>Policy Statement</u>

4. As noted above, the Commission through this policy statement provides additional guidance with respect to certain aspects of its incentives policies. Specifically, the Commission: reframes the nexus test to focus more directly on the requirements of Order No. 679; expects applicants to take all reasonable steps to mitigate the risks of a project, including requesting those incentives designed to reduce the risk of a project, before seeking an incentive ROE based on a project's risks and challenges; provides general guidance that may inform applications for an incentive ROE based on a project's risks and challenges; and promotes additional transparency with respect to the impacts of the Commission's incentives policies. Each of these issues and the Commission's corresponding clarifications are discussed further below.

5. We note that many aspects of the Commission's incentives policies are not addressed in this policy statement. For example, in Order No. 679, the Commission stated that applicants could seek incentives thereunder regardless of their ownership

structure,[3] and that the Commission would evaluate incentive applications on a case-by-case basis.[4] The Commission also established rebuttable presumptions to assist in determining whether proposed facilities satisfy the statutory threshold of section 219.[5] In Order No. 679 and subsequent cases applying incentives policies, the Commission has addressed the granting of incentive ROEs that are not based on the risks and challenges of a project, such as incentive ROEs for RTO membership or Transco formation. With respect to aspects of the Commission's incentives policies not addressed in this policy statement, we decline to provide additional guidance at this time.

A. Application of the Nexus Test

6. Order No. 679 established the "nexus test," which requires applicants to demonstrate a connection between the incentive(s) requested under Order No. 679 and the proposed investment, and that the incentive(s) requested address the risks and challenges that a project faces. In Order No. 679, the Commission stated that each incentive:

> "…will be rationally tailored to the risks and challenges faced in constructing new transmission. Not every incentive will be available for every new investment. Rather, each applicant must demonstrate that there is a nexus between the incentive sought and the investment being made. Our reforms therefore continue

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[3] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 4. Section 219(b)(1) requires that the Commission establish rules for incentives, "…regardless of the ownership of the facilities." 16 U.S.C. § 824s(b)(1).

[4] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 43.

[5] *Id.* P 58.

> to meet the just and reasonable standard by achieving the proper balance between consumer and investor interests on the facts of a particular case and considering the fact that our traditional policies have not adequately encouraged the construction of new transmission."[6]

7. The Commission refined the nexus test in Order No. 679-A, finding that, in applying the nexus test, the Commission should look at whether the total package of incentives is rationally tailored to the risks and challenges of constructing new transmission.[7] The Commission stated that this approach would protect consumers by recognizing that requested incentives that reduce risk might obviate the need for an incentive ROE based on a project's risks and challenges, or otherwise justify a lower incentive ROE based on a project's risks and challenges.

8. Subsequent to Order No. 679 and Order No. 679-A, the Commission further refined its application of the nexus test by clarifying that the determination of whether a project is "routine" or "non-routine" is particularly probative in evaluating whether the nexus test was satisfied. In *Baltimore Gas and Electric Company*, the Commission

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[6] *Id.* P 26.

[7] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 27. *See also* 18 C.F.R. § 35.35(d) (2006) ("Incentive-based rate treatments for transmission infrastructure investment. … The applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion consistent with the requirements of section 219, that the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project, and that resulting rates are just and reasonable.…")

concluded that, once an applicant demonstrates that a project is not routine, the nexus test is satisfied and the project is deemed to face risks and challenges that merit incentive(s).[8]

9. The Commission recognizes that there are a wide range of views on its application of the nexus test and, in particular, the Commission's use of the routine/non-routine analysis as a proxy for the nexus test. Most commenters in the NOI are supportive of the nexus test's focus on evaluating risks and challenges to determine whether a project merits incentives. Some commenters offer additional criteria for assessing risks and challenges, while others are more critical of the nexus test and assert that it is insufficient and requires change. With respect to the Commission's use of the routine/non-routine analysis in reviewing incentive applications since *BG&E*, some commenters support the continued use of the routine/non-routine analysis, while others seek more clarity from the Commission.

10. Based on experience to date with the application of Order No. 679, the Commission now believes it is essential to re-frame its application of the nexus test to focus more directly on the requirements adopted in Order Nos. 679 and 679-A.[9] The Commission will no longer rely on the routine/non-routine analysis adopted in *BG&E* as a proxy for the nexus test. While prior orders found that analysis probative, based on our experience to date applying our incentives policies and the comments received in

[8] 120 FERC ¶ 61,084, at PP 52-54 (2007) (*BG&E*).

[9] 18 C.F.R. § 35.35(d).

response to the NOI, we believe it is necessary to analyze the need for each individual incentive, and the total package of incentives, instead of relying on a proxy. Consistent with Order No. 679-A, the Commission will continue to require applicants seeking incentives to demonstrate how the total package of incentives requested is tailored to address demonstrable risks and challenges. Applicants "must provide sufficient explanation and support to allow the Commission to evaluate each element of the package and the interrelationship of all elements of the package. If some of the incentives would reduce the risks of the project, that fact will be taken into account in any request for an enhanced ROE."[10]

B. Risk-Reducing Incentives

11. The Commission authorizes a company's base ROE utilizing a range of reasonableness resulting from a discounted cash flow (DCF) analysis that is applied to a selected proxy group representing firms of comparable risk. The resulting base ROE authorized by the Commission is designed to account for many of the risks associated with transmission investment and to support that investment. Nonetheless, the Commission recognizes that there may be risks associated with investment in particular transmission projects that are not accounted for in the base ROE. In Order No. 679, the Commission recognized that some transmission incentives – such as recovery of 100 percent of Construction Work in Progress (CWIP), recovery of 100 percent of pre-

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[10] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 27.

commercial costs as an expense or as a regulatory asset, and recovery of 100 percent of prudently incurred costs of transmission facilities that are abandoned for reasons beyond the applicant's control – reduce the financial and regulatory risks associated with transmission investment.[11] The Commission reaffirms in this policy statement that these risk-reducing incentives may mitigate risk not accounted for in the base ROE, and we therefore expect incentives applicants to first examine the use of risk-reducing incentives before seeking an incentive ROE based on a project's risks and challenges.[12]

12. The CWIP and pre-commercial cost incentives both serve as useful tools to ease the financial pressures associated with transmission development by providing up-front regulatory certainty, rate stability and improved cash flow, which in turn can result in higher credit ratings and lower capital costs.[13] Specifically, the CWIP incentive addresses timing issues associated with the recovery of financing costs for large transmission investments and allows recovery of a return on construction costs during the construction period rather than delaying cost recovery until the plant is placed into service. The Commission has also found that allowing companies to include 100 percent

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[11] *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at PP 115, 117, and 163.

[12] The Commission clarifies that placing a priority on risk-reducing incentives does not require separate applications for risk-reducing incentives and an incentive ROE based on a project's risks and challenges. Rather, in a single application an applicant could first demonstrate how risk-reducing incentives are utilized and then seek to demonstrate, as discussed further below, that remaining risks and challenges merit an incentive ROE based on the project's risks and challenges.

[13] *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at PP 115, 117, and 163.

of CWIP in rate base would result in greater rate stability for customers by reducing the "rate shock" when certain large-scale transmission projects come on line.[14]

13. Regarding 100 percent recovery of pre-commercial cost as an incentive, the Commission has permitted recipients of this incentive to expense and recover pre-commercial costs that would otherwise be capitalized in CWIP, thus providing for earlier cost recovery and improving early stage project cash flows. The Commission has also made deferred cost recovery available to applicants to address cost recovery restrictions at the state level and to provide greater flexibility for applicants to recover costs, recognizing that deferred cost recovery is intended to "…increase the certainty of cost recovery to encourage more transmission investment."[15] The Commission also recognizes the usefulness of deferred cost recovery of pre-commercial costs for applicants who do not have a formula rate in effect prior to incurring pre-commercial costs, by allowing the applicant to defer all such costs not included in CWIP as a regulatory asset until the applicant has a formula rate in effect for cost recovery.[16] The Commission has previously found that this incentive provides up-front regulatory

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[14] *See, e.g., PJM Interconnection, L.L.C. and Pub. Serv. Elec. and Gas Co.*, 135 FERC ¶ 61,229 (2011). *See also PPL Elec. Utils. Corp* ., 123 FERC ¶ 61,068, at P 43 (2008), *reh'g denied* 124 FERC ¶ 61,229.

[15] Order No. 679, *FERC* Stats. & Regs. ¶ 31,222 at PP 175, 178.

[16] *See, e.g., Atlantic Grid*, 135 FERC ¶ 61,144 (2011). Like the pre-commercial cost incentive, all transmission incentives are intended to be available to all existing utilities and non-incumbent utilities.

certainty and can reduce interest expense, improve coverage ratios, and assist in the construction of transmission projects.[17]

14. Regarding the incentive that allows for 100 percent recovery of prudently incurred costs of transmission facilities that are abandoned for reasons beyond the control of the transmission owner, the Commission has found this incentive reduces the regulatory risk of non-recovery of prudently incurred costs.[18] The Commission has previously stated that, in addition to the challenges presented by the scope and size of a project, factors like various federal and state siting approvals introduce a significant element of risk. Granting this incentive ameliorates such risk by providing companies with more certainty during the pre-construction and construction periods.[19]

15. In the NOI, numerous commenters discuss the interplay of risk-reducing incentives on the need for and appropriate level of an incentive ROE. For example, Certain State and Consumer-Owned Entities state that if a project's risks exceed the risk that is accounted for in the base ROE, incentives may be appropriate.[20] Other

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[17] *See, e.g., DATC Midwest Holdings, L.L.C.*, 139 FERC ¶ 61,224 (2012).

[18] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 163.

[19] *See, e.g., PJM Interconnection, L.L.C. and Pub. Serv. Elec. and Gas Co.*, 135 FERC ¶ 61,229 (2011).

[20] Certain State and Consumer-Owned Entities September 12, 2011 Comments at 39. Certain State and Consumer-Owned Entities include Connecticut Public Utilities Regulatory Authority, Attorney General for the State of Connecticut, Connecticut Office of Consumer Counsel, Attorney General for the State of Delaware, Delaware Public Service Commission, Public Advocate of Delaware, Attorney General for the State of

(continued…)

commenters state that the Commission should strike an appropriate balance between consumer and investor interests, and that if incentives are compounded without consideration of the reduced risk effect of some of the incentives, this approach tips the risk in favor of the investor and to the detriment of the transmission customer. Numerous commenters also argue that risk-reducing incentives mitigate the need for an incentive ROE based on a project's risks and challenges to attract investment. For example, Joint Commenters[21] note that the biggest risks for transmission projects relate to siting and

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Illinois, Maine Public Utilities Commission, Attorney General for the Commonwealth of Massachusetts, Massachusetts Department of Public Utilities, Massachusetts Municipal Wholesale Electric Company, New England Conference of Public Utilities Commissioners, Attorney General for the State of New Hampshire, New Hampshire Electric Cooperative, Inc., New Hampshire Office of Consumer Advocate, New Hampshire Public Utilities Commission, Rhode Island Public Utilities Commission and Division of Public Utilities and Carriers, Attorney General for the State of Rhode Island, Vermont Department of Public Service, and Vermont Public Service Board.

[21] Joint Commenters include Joint Comments of American Forest & Paper Association, American Public Power Association, California Municipal Utilities Association, California Public Utilities Commission, City and County of San Francisco, Connecticut Office of Consumer Counsel, Electricity Consumers Resource Council, Indiana Utility Regulatory Commission, Maryland Office of People's Counsel, Modesto Irrigation District, Montana Public Service Commission, National Association of State Utility Consumer Advocates, New England Conference of Public Utilities Commissioners, New Hampshire Public Utilities Commission, New Jersey Board of Public Utilities, New Jersey Division of Rate Counsel, Northern California Power Agency, Office of the Nevada Attorney General, Bureau of Consumer Protection, Office of the Ohio Consumers' Counsel, Old Dominion Electric Cooperative, Organization of MISO States, Pennsylvania Office of Consumer Advocate, Public Power Council, Public Service Commission of the State of New York, Public Service Commission of Wisconsin, Sacramento Municipal Utility District, South Dakota Public Utilities Commission, State of Maine, Office of the Public Advocate, Transmission Agency of Northern California, the Vermont Department of Public Service, and the Vermont Public Service Board.

permitting delays, cash flow shortage, or abandonment concerns, but argue that, even where the level of these risks is unusually high, they can be mitigated by granting risk-reducing incentives. Joint Commenters further contend that, when incentives are appropriate, risk-reducing incentives should be the first (and often the only) incentives considered.[22] Other commenters point out that risk also is mitigated through the assurance of cost recovery at the state level.

16. In Order No. 679-A, the Commission stated that a project that receives risk-reducing transmission incentives, like those discussed above, would likely face lower risks. Therefore, that project may not warrant an incentive ROE, or may warrant a lower incentive ROE, based on the project's risks and challenges.[23] Based on the Commission's experience under Order No. 679, and after careful consideration of comments on the NOI as to the benefits of risk-reducing incentives, the Commission clarifies that many risks not accounted for in the base ROE can be alleviated through risk-reducing incentives such as those discussed earlier in this section. In cases where an incentive ROE based on risks and challenges is requested in combination with risk-reducing incentives, the Commission must carefully apply its total package analysis to ensure that the effect of the risk-reducing incentives is appropriately accounted for in determining whether an incentive ROE based on risks and challenges is warranted,

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[22] Joint Commenters September 12, 2011 Comments at 80.

[23] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 27.

and if warranted, what level is appropriate. For this reason, the Commission expects incentives applicants to seek to reduce the risk of transmission investment not otherwise accounted for in its base ROE by using risk-reducing incentives before seeking an incentive ROE based on a project's risks and challenges.[24]

C. Incentive ROEs Based on Project Risks and Challenges

17. Some commenters in the NOI suggest that the Commission specifically identify project characteristics or risks and challenges that would merit an incentive ROE. We decline to do so. Instead, we will continue to allow applicants the flexibility necessary to demonstrate why their projects may merit an incentive ROE, and at what level, based on those project's risks and challenges, but we provide general guidance below that may inform applications for this type of transmission incentive.

1. Showings and Commitments for Remaining Risks and Challenges

18. As discussed above, many of the risks not captured by traditional ratemaking policies can be addressed through risk-reducing incentives. While the record in the NOI proceeding does not show that incentive ROEs have resulted in significant rate increases

[24] The Commission appreciates that non-incumbents seeking incentives may face challenges implementing some risk-reducing incentives because they may not have the appropriate rate structures in place under which to effectuate these transmission incentives. In such instances, the Commission anticipates subsequent section 205 filings by non-incumbent incentive applicants for cost recovery. As noted above, all transmission incentives are intended to be available to all existing utilities and non-incumbent utilities.

for consumers,[25] incentive ROEs likely put more upward pressure on transmission rates than risk-reducing incentives. Therefore incentive applicants should first examine risk-reducing incentives.

19. However, a project may face certain risks and challenges that may not be addressed through either the traditional ratemaking policies or risk-reducing incentives. In such instances, an incentive ROE based on a project's risks and challenges may be appropriate.[26] Based on the Commission's experience under Order No. 679 and the comments received on the NOI, the Commission expects applicants seeking an incentive ROE based on a project's risks and challenges to make the following four showings as part of their application for that incentive.

a. <u>Identification of Risks and Challenges</u>

20. When applying for an incentive ROE based on the project's risks and challenges, applicants will first be expected to demonstrate that the proposed project faces risks and challenges that are not either already accounted for in the applicant's base ROE or addressed through risk-reducing incentives. To make this demonstration, the

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[25] *See*, ITC Holdings Corp. September 12, 2011 Comments at 16: "The incentives granted to transmission projects have had generally positive, not negative, effects on consumer rates and service, especially when improved reliability, reduced congestion and access to a more diverse supply of generation, including renewable resources, are taken into account. One reason for this is that the cost of transmission incentives is small compared to the cost of energy, distribution and congestion."

[26] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 94.

Commission suggests that applicants identify risks and challenges specific to the project for which an incentive ROE is being requested.

21. Investments in the following types of transmission projects[27] may face the types of risks and challenges that may warrant an incentive ROE based on the project's risks and challenges that are not either already accounted for in the applicant's base ROE or could be addressed through risk-reducing incentives:

1. projects to relieve chronic or severe grid congestion that has had demonstrated cost impacts to consumers;
2. projects that unlock location constrained generation resources that previously had limited or no access to the wholesale electricity markets;
3. projects that apply new technologies to facilitate more efficient and reliable usage and operation of existing or new facilities.[28]

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[27] These investments could include both investment in new transmission facilities, as well as investment in transmission upgrades, retrofits, and projects that modernize the existing transmission grid.

[28] Examples of projects that meet this description include those that create additional incremental capacity without significant construction (e.g., through the use of dynamic line rating), that allow for more efficient balancing of variable energy resources, and/or that provide increased grid stability. In addition, the Commission is concerned that its current practice of granting incentive ROEs and risk-reducing incentives may not be effectively encouraging the deployment of new technologies or the employment of practices that provide demonstrated benefits to consumers. Accordingly, the Commission remains open to alternative incentive proposals aimed at supporting projects that achieve these ends.

22. This list is not exhaustive, but rather indicative of the types of projects that the Commission believes, based on its experience and expertise with respect to industry trends and system investment needs, may warrant an incentive ROE based on the project's risks and challenges. More generally, the Commission anticipates that applicants will seek an incentive ROE based on a project's risks and challenges for projects that provide demonstrable consumer benefits by making the transmission grid more efficient, reliable, and cost-effective. Thus, consistent with our statements in Order No. 679, we note that reliability-driven projects may be considered for an incentive ROE based on a project's risks and challenges, but only if they present specific risks and challenges not otherwise mitigated by available risk-reducing incentives.[29]

23. Under our current incentive policies, the Commission considers an applicant's proposed use of an advanced transmission technology both: 1) as part of the overall nexus analysis, accounting for the risks and challenges associated with utilizing such advanced technology into that overall nexus analysis;[30] and 2) where an applicant seeks a stand-alone incentive ROE based on its utilization of an advanced technology.[31] The

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[29] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 94.

[30] *See Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248, at P 59 (2008) ("[t]he associated challenges can be incorporated into the overall nexus analysis, but the technology does not, in and of itself, appear to justify a separate advanced technology adder."); *RITELine Indiana & Illinois LLC*, 137 FERC ¶ 61,039 at P 62 (2011).

[31] *See The United Illuminating Co.*, 126 FERC ¶ 61,043, at P 14 (2009) ("In reviewing requests for separate adders for advanced technology, the Commission reviews record evidence to decide if the proposed technology warrants a separate adder because it

(continued…)

Commission continues to encourage the deployment of advanced technologies that "increase the capacity, efficiency, or reliability of an existing or new transmission facility."[32] However, the Commission is concerned that its current approach may contribute to confusion, including with respect to the distinct standards that the Commission applies in these two contexts. To address this concern, the Commission will no longer consider requests under Order No. 679 for a stand-alone incentive ROE based on an applicant's utilization of an advanced technology. Instead, as noted above, the Commission will consider transmission projects that apply advanced technologies as indicative of the types of projects facing risks and challenges that may warrant an incentive ROE. As a result, we will consider deployment of advanced technologies as part of the overall nexus analysis when an incentive ROE is sought.

b. <u>Minimization of Risks</u>

24. The Commission expects an applicant that requests an incentive ROE based on a project's risks and challenges to demonstrate that it is taking appropriate steps and using appropriate mechanisms to minimize its risks during project development. For example, risks may be reduced through the risk-reducing incentives described in section II.B, or through mitigating costs by implementing best practices in their project management and

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reflects a new or innovative domestic use of the technology that will improve reliability, reduce congestion, or improve technology."). *See also NSTAR Elec. Co.*, 127 FERC ¶ 61,052 at P 27 (2009).

[32] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 298.

procurement procedures. Applicants should consider taking measures tailored to mitigate the various risks associated with their transmission projects and to identify such measures in their applications. For example, applicants may take measures to mitigate risks associated with siting and environmental impacts by pursuing joint ownership arrangements. The Commission encourages incentives applicants to participate in joint ownership arrangements and agrees with commenters to the NOI that such arrangements can be beneficial by diversifying financial risk across multiple owners and minimizing siting risks.[33]

c. Consideration of Alternatives

25. The Commission expects applicants for an incentive ROE based on a project's risks and challenges to demonstrate that alternatives to the project have been, or will be, considered in either a relevant transmission planning process or another appropriate forum. Such a showing should help identify the demonstrable consumer benefits of the proposed project and its role in promoting a more efficient, reliable and cost-effective transmission system.[34]

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[33] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at PP 354, 357; Order No. 679-A FERC Stats. & Regs. ¶ 31,236, at P 102. *See also Central Maine Power Company*, 125 FERC ¶ 61,182, at P 61 (2008); *Xcel Energy*, 121 FERC ¶ 61,284 at P 55 (2007). Evidence regarding whether an applicant for incentives considered joint ownership arrangements may be relevant in assessing whether the applicant took appropriate steps to minimize its risks during project development.

[34] This showing draws on recommendations made by commenters in the NOI, who suggested that the Commission require an assessment of lower cost alternatives to any proposed transmission project as part of a filing requesting transmission incentives.

26. The Commission appreciates that there may be timing challenges for applicants making this showing, and thus the Commission will be flexible in the approaches it allows for applicants to make this showing. In particular, this showing could be satisfied through participation in open processes that are already in existence. For example:

1. The applicant could show that its project was, or will be, considered in an Order No. 890 or Order No. 1000-compliant transmission planning process that provides the opportunity for projects to be compared against transmission or non-transmission alternatives.[35]
2. The applicant could show that its project was considered by a local regulatory body, such as a state utility commission, that evaluated alternatives to its proposed project (transmission or non-transmission alternatives) and determined that the proposed transmission project is preferable to the alternatives evaluated.

27. The above approaches should not be seen as exclusive, however, and the Commission will remain open to alternative methods to making this showing.[36]

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[35] In making this showing, the applicant need not show that its project was selected in a regional transmission plan for purposes of cost allocation. Instead, the focus would be on whether the project was or will be considered in a process where it could be compared to other projects and shown to be preferable to any alternatives that were evaluated.

[36] For example, projects that are required to complete an environmental impact statement (EIS) may submit the analysis on the consideration of alternatives, per the requirements of the EIS, as making such a showing.

d. <u>Commitment to Cost Estimates</u>

28. Finally, the Commission expects applicants for an incentive ROE based on a project's risks and challenges to commit to limiting the application of the incentive ROE based on a project's risks and challenges to a cost estimate. For example, the Commission has approved an applicant's proposal to limit the incentive ROE based on a project's risks and challenges to the cost estimate utilized at the time of RTO approval.[37] Our intent is not to be prescriptive as to how applicants might structure this commitment; instead, the Commission is open to approaches that control transmission development costs and provide more transparency regarding how incentives will be applied to costs beyond initial estimates.[38]

29. The Commission recognizes the challenges of determining the appropriate cost estimate for a project. For example, most applicants seek incentives from the Commission at a relatively early stage in the project development process, often before state siting or other processes raise challenges that can impact the design and ultimate cost of a project. One option may be for applicants to commit to limiting the application

[37] *RITELine Illinois & Indiana LLC*, 137 FERC ¶ 61,039, at P 5 (2011).

[38] Concern about the effects of allowing transmission incentives to be applied to costs over those estimated was expressed by a number of commenters in the NOI proceeding.

of an incentive ROE based on a project's risks and challenges to the last cost estimate relied upon to include or retain the project in a regional transmission planning process.[39]

30. The Southwest Power Pool Regional State Committee (SPP RSC) in its comments on the NOI identifies a definitive cost estimate that would serve as the initial threshold limit for an incentive ROE, a 10% dead-band above or below the definitive cost estimate around which changes in costs are shared equally between shareholders and customers, and a provision for addressing cost increases that are outside the control of the transmission owner.[40] The Commission believes that aspects of the SPP RSC proposal highlighted here may provide useful guidance to applicants when seeking incentive ROEs based on a project's risks and challenges.

III. Conclusion

31. As noted above, the Commission is relying on its experience and expertise with respect to industry trends and system investment needs to provide additional guidance and clarity through this policy statement. Six years after issuing Order No. 679, the Commission believes that it is appropriate and in the public interest to evaluate the impacts of its incentives policy and give guidance as to how the Commission will implement that incentives policy going forward. In order to further the mandate of FPA

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[39] If factors outside applicant's control cause significant deviation from the cost estimate upon which the ROE incentive was initially granted, the Commission can revisit that cost estimate (e.g., a regional planner requires significant acceleration of a project construction timeline).

[40] SPP RSC September 12 Comments at 5, 12-13.

section 219 and encourage transmission investment in the future, the Commission will continue to monitor its incentives policy and may identify new policy issues, trends, and developments in transmission investment that may warrant modifications to the Commission's incentives policy. As part of this effort, the Commission will continually assess measures to further transparency in its incentives policy and the impacts of that policy on consumers.

IV. Document Availability

32. In addition to publishing the full text of this document in the *Federal Register*, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

33. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

34. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at 202-502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By the Commission. Commissioner Clark is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

137 FERC ¶ 61,039
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

RITELine Illinois, LLC	Docket Nos. ER11-4069-000
RITELine Indiana, LLC	ER11-4070-000

ORDER ON TRANSMISSION RATE INCENTIVES AND FORMULA RATE PROPOSAL

(Issued October 14, 2011)

1. On July 18, 2011, RITELine Illinois, LLC (RITELine Illinois) and RITELine Indiana, LLC (RITELine Indiana) (collectively, RITELine Companies) filed an application, pursuant to sections 205 and 219 of the Federal Power Act (FPA)[1] and Order No. 679,[2] for acceptance of a formula rate and approval of rate incentives for the Reliability Interregional Transmission Extension Project (RITELine Project or Project). For the reasons discussed below, we will accept in part, and reject in part, the proposal, to be effective October 17, 2011, as requested. We also direct the RITELine Companies to submit compliance filings within 30 days of the issuance of this order, as discussed below.

I. **Proposal**

A. **Petitioners**

2. The RITELine Project is being developed by American Electric Power Company (AEP), Commonwealth Edison (ComEd), Electric Transmission America, LLC (ETA),[3]

[1] 16 U.S.C. §§ 824d; 824s (2006).

[2] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

[3] ETA is a joint venture between AEP Transmission Holding Company, LLC (ATHC), and MidAmerican Energy Holdings Company America Transco, LLC.

and RITELine Transmission Development, LLC (RTD), which is comprised of ETA and Exelon Transmission Company (ETC), a wholly-owned subsidiary of Exelon Corporation (collectively, Project Developers). RITELine Illinois and RITELine Indiana will be the public utility operating companies of the RITELine Project.[4] RITELine Illinois will own the Illinois portion of the Project, and RITELine Indiana will own the Indiana portion of the Project. The RITELine Companies state that they will recover costs through a single formula rate and will transfer functional control of the Project to PJM Interconnection, LLC (PJM) once it's completed.[5]

B. Description of the Project

3. The RITELine Companies describe the Project as an approximately 420-mile, 765 kV project that will strengthen the transmission system in Illinois, Indiana, and Ohio. The Project will include five 765 kV substations and other appurtenant transmission facilities. In addition, the Project is expected to permit the integration of approximately 5,000 megawatt (MW) of additional renewable generation. The RITELine Companies state that they expect the Project to be placed into service approximately five to six years after obtaining regional transmission expansion plan (RTEP) approval by PJM, and has an estimated cost of $1.6 billion. Further, the RITELine Companies state that the Project will interconnect with a portion of the proposed Pioneer Transmission, LLC 765 kV project (Pioneer Project).

4. The RITELine Companies state that the Project will begin at a new Blue Creek substation on the Indiana/Ohio border, running west through Indiana to Kewanee, Illinois, and then north to Byron, Illinois. In addition, there is a segment from Kewanee to Collins that connects to ComEd's 765 kV transmission system in Illinois. The RITELine Companies state that the Indiana portion will run from the Illinois-Indiana border to the proposed Meadow Lake substation, where it will be connected with the Pioneer Project to AEP's Greentown substation, and then run from the Greentown substation to the Blue Creek substation.[6]

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[4] RITELine Illinois will be owned 25 percent by RTD and 75 percent by ComEd. RITELine Indiana will be owned 25 percent by RTD, 37.5 percent by ATHC, and 37.5 percent by ETA.

[5] Transmittal Letter at 3.

[6] *Id.* at 4-7.

C. **Request for Incentives**

5. The RITELine Companies request several transmission rate incentives pursuant to sections 205 and 219 of the FPA and Order No. 679. First, the RITELine Companies request an overall return on equity (ROE) of 12.7 percent. However, the RITELine Companies state that they can support an incentive ROE of 13.2 percent, which includes a base ROE of 10.7 percent plus ROE adders of: (1) 50 basis points for regional transmission organization (RTO) participation; (2) 50 basis points for the use of advanced transmission technology; and (3) 150 basis points to compensate for the risks and challenges associated with investing in new transmission (risk adder). The RITELine Companies propose that the risk adder only apply to the project cost estimate established at the time of RTO approval, unless the cost of the Project is increased due to changes required as a result of the siting process and/or changes specifically directed by PJM. The RITELine Companies state that cost increases other than those incurred due to the siting process or to comply with changes required by PJM would not qualify for the risk adder.

6. Second, the RITELine Companies seek authorization for 100 percent construction work in progress (CWIP) in rate base during the development and construction period for the Project. They state that they face significant financial challenges, and 100 percent CWIP recovery will alleviate further downward pressures on their financial condition by ensuring adequate cash flow.[7]

7. Third, the RITELine Companies request approval to recover 100 percent of their prudently-incurred costs associated with the Project in the event that the Project must be abandoned for reasons outside of their control. They state that this incentive is appropriate because the Project has not received PJM RTEP approval, and the RITELine Companies may fail to obtain the requisite regulatory approvals or the necessary rights-of-way.[8]

8. Fourth, the RITELine Companies seek authorization to establish a regulatory asset that will include all expenses not capitalized and included in CWIP that are incurred in connection with the Project prior to the rate year in which costs are first flowed through to customers pursuant to PJM's open access transmission tariff (OATT), including authorization to amortize the regulatory asset with interest over five years for cost recovery purposes. Further, the RITELine Companies request authorization to use the

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[7] *Id.* at 40.

[8] *Id.* at 41-42.

allowance for funds used during construction (AFUDC) rate for accrual purposes until the regulatory asset is included in rate base.[9]

9. Fifth, the RITELine Companies request approval of a hypothetical capital structure of 55 percent equity and 45 percent debt until long-term financing is in place and the Project has been placed into service.[10]

D. Formula Rate Proposal

10. The RITELine Companies also propose to establish a formula rate and protocols, under which costs are projected and then trued up to actual costs once they are known. The RITELine Companies state that the proposed formula rate is designed to track increases and decreases in actual costs and projected capital addition. In addition, a true-up mechanism will be implemented at the end of each rate period to ensure that any deviation from actual costs during the rate period is reflected in an adjustment (with interest) to the annual transmission revenue requirement in the subsequent rate period. They further state that the formula rate provides for the recovery of: (1) a return on rate base and associated taxes; (2) taxes other than income taxes; (3) depreciation expense; and (4) other operation and maintenance expenses, less revenue credits. The RITELine Companies explain that they will not assess charges to customers until the Project is included in PJM's RTEP, at which time the formula rate and protocols will be resubmitted by PJM to be incorporated in the PJM tariff.[11]

E. Technology Statement

11. The RITELine Companies state that they are entitled to an additional ROE incentive of 50 basis points because they are employing advanced technologies which they claim will positively impact reliability, efficiency, and environmental sensitivity in the manner Congress intended through section 1223 of the Energy Policy Act of 2005 as implemented by the Commission through Order No. 679.[12] The RITELine Companies request the ROE incentive adder for the use of one advanced transmission technology associated with advanced conductor design. Specifically, the RITELine Project will use a six-conductor bundle in conjunction with trapezoidal stranded conductors. The

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[9] *Id.* at 8 n.9.

[10] *Id.* at 8-9.

[11] *Id.* at 49-52.

[12] *Id.* at 63; Ex. RIT-201 at 3 (citing Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (2005)).

RITELine Companies explain that they will use a number of other advanced transmission technologies to enhance the performance of the RITELine Project, which include: (1) efficient and resilient transformers and reactors; (2) phase and shield wire transposition; (3) fiber-optic shield wires; (4) wide-area monitoring and control; (5) remote station equipment diagnostics and security; and (6) switchable shunt reactors.

12. According to the RITELine Companies, use of a six-conductor bundle, as opposed to a four-conductor bundle, will reduce line-loss by approximately 20 percent for resistive losses and 60 percent for corona losses compared to similarly situated 765 kV lines. In addition, the RITELine Companies state that the six-conductor design will reduce audible noise and broadcast frequency interference. The RITELine Companies note that six-conductor bundles is a technology previously used on only one recently built line, AEP's Jackson Ferry-Wyoming line in West Virginia and Virginia. In addition, the RITELine Companies note that the line-losses on the RITELine Project will be reduced even further by incorporating trapezoidal stranded conductors in the bundled design, a technology that the RITELine Companies state has never been previously used for 765 kV lines.[13]

F. SMART Study and MISO's Regional Generator Outlet Study

13. The RITELine Companies state that prior to agreeing to collaborate on the development of the Project, AEP and Exelon Corporation conducted various transmission studies that indicated the need to strengthen the extra high voltage (EHV) transmission system in the Midwest. In addition, the RITELine Companies state that various regional studies have focused on the need to strengthen the Midwest transmission grid in order to accommodate the growing development of renewable energy projects and to address numerous reliability concerns. The RITELine Companies explain that the RITELine Project study process was built upon the analyses undertaken in these studies. In particular, the RITELine Companies submit two studies for the Commission's review: (1) the Strategic Midwest Area Transmission (SMART) Study; and (2) the Midwest Independent System Operator, Inc. (MISO) Regional Generator Outlet Study (RGOS).[14]

14. The RITELine Companies state that the SMART Study is the result of ETA, together with American Transmission Company, Xcel Energy, Exelon Corporation, MidAmerican Energy Company, and NorthWestern Energy studying the development of an EHV transmission overlay in the upper Midwest portion of the country. The study analyzes the reliability and economic benefits of an overlay project, as well as the potential to interconnect and deliver substantial amounts of wind-powered generation that

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[13] Ex. RIT-200 at 46-48.

[14] *Id.* at 10.

could be developed to meet current and future state and potentially federal renewable portfolio standards (RPS). In addition, the RITELine Companies state that the study sponsors hired Quanta Technology LLC, an independent consulting firm, to undertake a study of alternatives, using various assumptions, which would permit participants to evaluate and rank the alternatives.

15. The RITELine Companies explain that Phase I of the SMART Study focused on various overlay alternatives designed to enable the integration of over 56 gigawatts of wind generation, and to provide significant reliability and economic benefits to the region. Phase II of the SMART Study, which was conducted by Quanta Technology LLC, evaluated the economic benefits for the alternatives that were selected in Phase I. The RITELine Companies note that the RITELine Project was a key component in both of the preferred alternatives that were identified in Phases I and II of the SMART Study.[15]

16. The RITELine Companies state that the MISO RGOS was designed to study the potential development of a set of regionally coordinated transmission projects that would be planned and designed to enable MISO members and load-serving entities within the MISO footprint to meet both state RPS obligations and renewable energy goals at the least cost to consumers. The RITELine Companies explain that the MISO RGOS was designed to provide MISO members and stakeholders a platform to analyze alternative transmission plans to reliably and economically interconnect renewable resources across the Midwest. In addition, the RITELine Companies state that the RITELine Project is part of the 765 kV overlay developed in the MISO RGOS.[16]

II. <u>Notice of Filing and Responsive Pleadings</u>

17. Notice of the RITELine Companies' filing was published in the *Federal Register*, 76 Fed. Reg. 44,319 (2011), with interventions and protests due on or before August 8, 2011. The Illinois Commerce Commission (Illinois Commission) submitted a notice of intervention, and the PSEG Companies,[17] Exelon Corporation, and the PPL PJM Companies[18] filed timely motions to intervene. Clean Line Energy Partners LLC

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[15] *Id.* at 10-11.

[16] *Id.* at 11-12.

[17] The PSEG Companies are comprised of: Public Service Electric and Gas Company, PSEG Power LLC, and PSEG Energy Resources & Trade LLC.

[18] The PPL PJM Companies for this filing consist of: PPL Electric Utilities Corporation; PPL EnergyPlus, LLC; PPL Brunner Island, LLC; PPL Holtwood, LLC;

(continued)

(Clean Line Energy) submitted a timely motion to intervene and comments in support of the filing. In addition to their timely intervention, the PSEG Companies filed a timely protest.

18. On August 17, 2011, the Illinois Commission submitted comments out-of-time. In addition, on October 12, 2011, Northern Indiana Public Service Company filed a motion to intervene out-of-time.

19. On August 23, 2011, and September 1, 2011, the RITELine Companies submitted answers to the PSEG Companies' protest and the Illinois Commission's comments, respectively.

III. Discussion

A. Procedural Matters

20. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2011), the notice of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2011), we will grant Northern Indiana Public Service Company's late-filed motion to intervene given its interest in this proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

21. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2011), prohibits an answer to a protest, unless otherwise ordered by the decisional authority. We will accept the RITELine Companies' answers because they have provided information that assisted us in our decision-making process.

B. Section 219 Requirement

22. In Energy Policy Act of 2005,[19] Congress added section 219 to the FPA, directing the Commission to establish, by rule, incentive-based rate treatments to promote capital investment in transmission infrastructure. The Commission subsequently issued Order No. 679, which sets forth processes by which a public utility may seek transmission rate incentives pursuant to section 219, including the incentives requested here by the RITELine Companies.

PPL Martins Creek, LLC; PPL Montour, LLC; PPL Susquehanna, LLC; Lower Mount Bethel Energy, LLC; PPL New Jersey Solar, LLC; PPL New Jersey Biogas, LLC; and PPL Renewable Energy, LLC.

[19] Pub. L. No. 109-58, § 1241, 119 Stat. 594.

23. Pursuant to section 219, an applicant must show that "the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion."[20] Also, as part of this demonstration, "section 219(d) provides that all rates approved under the Rule are subject to the requirements of sections 205 and 206 of the FPA, which require that all rates, charges, terms and conditions be just and reasonable and not unduly discriminatory or preferential."[21]

24. Order No. 679 provides that a public utility may file a petition for declaratory order or a section 205 filing to obtain incentive rate treatment for transmission infrastructure investment that satisfies the requirements of section 219, i.e., the applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion.[22] Order No. 679 established a process for an applicant to follow to demonstrate that it meets this standard, including a rebuttable presumption that the standard is met if: (1) the transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or (2) a project has received construction approval from an appropriate state commission or state siting authority.[23] Order No. 679-A clarifies the operation of this rebuttable presumption by noting that the authorities and/or processes on which it is based (i.e., a regional planning process, a state commission, or siting authority) must, in fact, consider whether the project ensures reliability or reduces the cost of delivered power by reducing congestion.[24]

1. Proposal

25. The RITELine Companies acknowledge that they do not meet the rebuttable presumption under Order No. 679 but believe that they provide enough evidence for the Commission to make an independent finding under section 219. The RITELine Companies state that the incentives requested are supported by comprehensive economic and engineering analyses that are based upon extensive powerflow studies and production cost studies. Specifically, the RITELine Companies state that the RITELine Project will ensure reliability by alleviating current transmission loading issues in northern Illinois

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[20] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 76.

[21] *Id.* P 8 (citing 16 U.S.C. §§ 824(d)-(e)).

[22] 18 C.F.R. § 35.35(i) (2011).

[23] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 58.

[24] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 49.

and Indiana that are expected to worsen as state RPS requirements "ramp up further" and additional wind generation is developed in western MISO, Illinois, and Indiana. For example, the RITELine Companies explain that the powerflow analyses demonstrate, based on a 2016 base case, that first contingency and double contingency violations decrease from 14 to 2 first contingencies and from 29 to 15 double contingencies with the RITELine Project in-service. In addition, the RITELine Companies state that first contingency incremental transfer capability and first contingency total transfer capability analyses were performed and demonstrated that the RITELine Project will enable the integration of 5,000 MW nameplate capacity of new wind generation in Indiana, Illinois and the western MISO.[25]

26. In addition, the RITELine Companies state that the Project will reduce the cost of delivered power by reducing congestion and support integration of renewable generation to meet state RPS standards.[26] For example, the RITELine Companies explain that the Brattle Testimony's PROMOD market simulation shows that the 2021 locational marginal prices would be reduced from $5.90/MWh to $3.80/MWh between ComEd and the Indiana and southern Michigan portion of AEP, and from $8.10/MWh to $6.40/MWh between ComEd and the Ohio portion of AEP. In addition, the Brattle Testimony concludes that the combination of additional wind integration and congestion relief offered by the RITELine Project would reduce system-wide production costs by $630 million annually.

2. <u>Protests and Comments</u>

27. The PSEG Companies argue that the RITELine Companies cite to irrelevant or inappropriate factors or information in support of their assertion that the Project would provide reliability and congestion benefits. For instance, the PSEG Companies argue that the RITELine Companies' reliance on the SMART study and the MISO RGOS are no substitute for studies conducted by the Commission-approved planner for the region in which the Project will be developed. The PSEG Companies argue that neither MISO nor the SMART study participants have responsibility for planning transmission in the PJM region. For this reason, the PSEG Companies argue that it is of no consequence whether the RITELine Project was included in the MISO study or the SMART study. The PSEG Companies argue that the only point relevant is that the Project has not been evaluated by the PJM RTEP process.[27]

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[25] Transmittal Letter at 22-25.

[26] *Id.* at 26 (citing Ex. RIT-600 at 15-51 (Brattle Testimony)).

[27] PSEG Companies Protest at 5-7.

28. With regard to the Project's reliability benefits, the PSEG Companies argue that the RITELine Companies have failed to assert that there are any North American Electric Reliability Corporation (NERC) Reliability Criteria violations that are in fact unaddressed by PJM's existing RTEP or operational processes. The PSEG Companies argue that the RITELine Companies merely speculate about potential reliability violations and make broad-brush generalizations suggesting that every Transmission Loading Relief event or every switching event has a reliability impact. The PSEG Companies argue that, although the RITELine Companies point to PJM studies indicating the need to build certain transmission facilities, the facilities that PJM determined were needed did not include the RITELine Project. Therefore, the PSEG Companies state that there has been no determination by PJM that the RITELine Project is in fact needed for reliability.[28]

29. With regard to the Project's congestion benefits, the PSEG Companies contest the source of the Brattle report's assumptions regarding the quantity of wind generation that should be modeled. Specifically, the PSEG Companies contest the following assumptions made by the Brattle report's authors: "refined the wind assumptions for PJM based on an analysis conducted by PJM's Regional Planning Task Force"[29] (RPPTF) and other data. The PSEG Companies argue that the RPPTF is a stakeholder body that does not itself conduct any analyses. The PSEG Companies note that the RPPTF reviews presentations by both PJM and other stakeholders, but there is no indication in the Brattle Testimony of what materials the RPPTF or the Brattle authors actually relied on.[30]

30. The PSEG Companies also argue that PJM RTEP approval is required under Order No. 1000[31] as a prerequisite to regional cost allocation. The PSEG Companies state that PJM RTEP approval ensures that proposed projects will be properly vetted with an opportunity for input by representatives of the parties who will pay for the projects.[32] The PSEG Companies argue that when a developer is seeking regional cost allocation but

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[28] *Id.* at 7-8.

[29] *Id.* at 8 (quoting Ex. RIT-303 at 6).

[30] *Id.*

[31] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 Fed. Reg. 49,842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011).

[32] PSEG Companies Protest at 14-15 (citing Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 539).

has opted not to first obtain RTEP approval, then that proposal should be deemed premature and the developer should be directed to submit their proposal through the regional transmission planning process. Alternatively, the PSEG Companies state that the Commission must condition the effectiveness of any rate or the award of any incentives to be recovered upon PJM RTEP approval.[33]

3. Answer

31. The RITELine Companies argue that the PSEG Companies did not submit any analyses that call into question the accuracy of the comprehensive economic and reliability planning studies submitted with the RITELine filing. The RITELine Companies further state that the PSEG Companies' primary concern regarding the various studies they submitted to support their conclusions is that these studies do not substitute for the analysis required in the PJM RTEP. The RITELine Companies do not dispute this claim.[34]

4. Commission Determination

32. Order No. 679 requires that an applicant seeking incentive rate treatment for transmission infrastructure investment to demonstrate that the facilities for which it seeks an incentive either ensure reliability or reduce the cost of delivered power by reducing transmission congestion.[35] Order No. 679 establishes a rebuttable presumption that this standard is met if the transmission project results from a fair and open regional planning process that considers and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission, or if a project has received construction approval from an appropriate state commission or state siting authority.[36]

33. However, the Commission has stated that a project that does not qualify for the rebuttable presumption may nevertheless satisfy the FPA section 219 standards if the project sponsor presents a factual record supporting a finding that the project is needed to maintain reliability or reduce congestion.[37] In order to meet this requirement, a project sponsor may present detailed studies, engineering affidavits, or state siting approvals

[33] *Id.* at 15.

[34] RITELine Companies' August 23, 2011 Answer at 5-6.

[35] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 57-58.

[36] *Id.*

[37] *Id.* P 57.

demonstrating that the FPA section 219 criteria are met.[38] The Commission also has stated that it will consider incentive requests for projects that are still undergoing consideration in a regional planning process, but may make any requested incentive rate treatment contingent on the project being approved under the regional planning process.[39]

34. The RITELine Companies are not entitled to a rebuttable presumption that the Project satisfies the requirements of section 219 because the Project has not been approved in PJM's planning process or received siting approval from the relevant state siting authorities. However, the RITELine Companies have included studies in their filing attempting to support their assertion that the Project ensures reliability and/or reduces the cost of delivered power by reducing congestion. We have evaluated these studies and find that the RITELine Companies have not sufficiently demonstrated that the Project will ensure reliability or reduce the cost of delivered power by reducing congestion.

35. The Commission has previously granted requests for rate incentives for projects that have not relied on section 219's rebuttable presumption. However, in those cases, the applicants clearly demonstrated reliability or congestion concerns that the proposed project would address and supported such assertions with comprehensive and clear data, as well as internal and, in several cases, external studies.[40] By contrast, in several recent cases, applicants have neither relied on Order No. 679's rebuttable presumptions nor made a sufficient independent demonstration that the proposed projects would ensure reliability or reduce the cost of delivered power by reducing congestion.[41]

36. Here, the RITELine Companies have not provided the Commission with the necessary support to determine whether the Project ensures reliability or reduces the cost of delivered power by reducing congestion. The congestion study submitted by the RITELine Companies relies heavily on the ability of the Project to reduce congestion by

[38] *See Duquesne Light Co.*, 118 FERC ¶ 61,087, at P 68 (2007); *see also Green Power Express LP*, 127 FERC ¶ 61,031, at P 41 (2009) (*Green Power Express*).

[39] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 58 & n.39.

[40] *See, e.g.*, *Green Power Express*, 127 FERC ¶ 61,031; *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 (2009); *Tallgrass Transmission, LLC*, 125 FERC ¶ 61,248 (2008) (*Tallgrass*).

[41] *Primary Power, LLC*, 131 FERC ¶ 61,015 (2010) (*Primary Power*); *W. Grid Dev., LLC*, 130 FERC ¶ 61,056 (2010) (*Western Grid*); *S. Cal. Edison Co.*, 129 FERC ¶ 61,246 (2009) (*SoCal Edison*); *Green Energy Express, LLC*, 129 FERC ¶ 61,165 (2009) (*Green Energy Express*), *order on reh'g*, 130 FERC ¶ 61,117 (2010).

integrating approximately 5,000 MW of additional wind generation in Illinois and nearby MISO regions.[42] However, although there are substantial amounts of wind generation in the PJM and MISO generator interconnection queues, there is no guarantee that these projects will be built. In addition, the congestion study had several significant refinements to the modeling assumptions regarding the amounts, types, and placement of new renewable generation capacity in the PJM region.[43] For example, the RITELine Companies' wind assumptions were based on PJM's RPPTF that used 32,000 MW as a target for wind procurement for PJM by 2021, which exceeds the 24,400 MW of wind generation assumed to be installed within the PJM footprint in the MISO model. Of this 32,000 MW wind generation needed to meet PJM RPS requirements, the RITELine Companies assumed that 8,000 MW of wind generation would be imported from MISO, which yielded the total PJM wind capacity. It is unclear what the study relied on to make these assumptions and, consequently, it is unclear what the congestion benefits of the Project would be absent these assumptions.

37. The Commission also finds that the reliability study submitted by the RITELine Companies is insufficient to satisfy the threshold section 219 requirement. That study reflects a 2016 light load model and a 2021 shoulder peak model. The RITELine Companies state that these two load levels were chosen because light load periods are when transmission loading issues have been occurring as energy is moved west-to-east in MISO and PJM.[44] However, it is unclear whether the reliability violations that the RITELine Companies claim that the Project would mitigate are unaddressed by PJM's RTEP process. The RITELine Companies state that PJM has approved changes to its current planning studies to analyze the reliability concern that the RITELine Project is intended to address.

38. The insufficiency of the above-noted studies does not require rejection of the RITELine Companies' request for incentives. Rather, the Commission has previously found that the PJM RTEP is a fair and open regional transmission planning process that evaluates projects for reliability and/or congestion effects.[45] Therefore, we will approve

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[42] Ex. RIT-303 at 1.

[43] *Id.* at 2.

[44] Ex. RIT-200 at 30.

[45] *E.g.*, *PJM Interconnection, L.L.C.*, 133 FERC ¶ 61,273, at P 41 (2010); *see also Baltimore Gas & Elec. Co.*, 120 FERC ¶ 61,084, at P 41 (2007) (*BG&E*), *order granting incentive proposal*, 121 FERC ¶ 61,167 (2007), *reh'g denied*, 122 FERC ¶ 61,034, *reh'g denied*, 123 FERC ¶ 61,262 (2008); *Duquesne Light Co.*, 118 FERC ¶ 61,087 at P 62-68; *Virginia Elec. & Power Co.*, 124 FERC ¶ 61,207, at P 32.

incentives as discussed herein, conditioned upon the Project being included in the PJM RTEP. We direct the RITELine Companies to submit a compliance filing within 30 days of the approval of the Project in the PJM RTEP, notifying the Commission of any such approval. The RITELine Companies must provide in this compliance filing evidence that the planning process included a finding that the Project will ensure reliability or reduce the cost of delivered power by reducing congestion, consistent with Order No. 679-A.[46]

39. With regard to the PSEG Companies' argument that Order No. 1000 requires RTEP approval as a prerequisite to regional cost allocation, the RITELine Companies are not seeking regional cost allocation in this filing. Furthermore, the RITELine Companies acknowledge in their answer that regional planning approval is a prerequisite for their formula rate to be included under Schedule 12 of the PJM OATT.[47] Accordingly, we reject this argument as beyond the scope of the filing.

C. Order No. 679 Nexus Requirement

40. In addition to satisfying the section 219 requirement of ensuring reliability and/or reducing the cost of delivered power by reducing congestion, an applicant must demonstrate that there is a nexus between the incentive sought and the investment being made. In Order No. 679-A, the Commission clarified that the nexus test is met when an applicant demonstrates that the total package of incentives requested is "tailored to address the demonstrable risks or challenges faced by the applicant."[48] The Commission noted that this nexus test is fact-specific and requires the Commission to review each application on a case-by-case basis.

41. As part of this evaluation, the Commission has found the question of whether a project is routine to be particularly probative.[49] In *BG&E*, the Commission clarified how it will evaluate projects to determine whether they are routine. Specifically, to determine whether a project is routine, the Commission will consider all relevant factors presented by an applicant. For example, an applicant may present evidence on: (1) the scope of the project (e.g., dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (2) the effect of the project (e.g.,

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[46] *See* Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 49; *see also Central Maine Power Company*, 125 FERC ¶ 61,182, at P 57 (2008).

[47] RITELine Companies August 23, 2011 Answer at 6.

[48] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 40.

[49] *BG&E*, 120 FERC ¶ 61,084 at P 48.

improving reliability or reducing congestion costs); and (3) the challenges or risks faced by the project (e.g., siting, internal competition for financing with other projects, long lead times, regulatory and political risks, specific financing challenges, other impediments).[50] Additionally, the Commission clarified that "when an applicant has adequately demonstrated that the project for which it requests an incentive is not routine, that applicant has, for purposes of the nexus test, shown that the project faces risks and challenges that merit an incentive."[51]

1. Proposal

42. The RITELine Companies argue that they meet the nexus requirement due to the scope, effects, and risks and challenges associated with the Project.[52] The RITELine Companies state that the Project, with an estimated cost of $1.6 billion ($1.2 billion invested in Illinois and $0.4 billion invested in Indiana), is among the largest projects that the Commission has reviewed for incentive rate treatment from a cost perspective. And, the RITELine Companies state that it is one of the most expensive transmission projects undertaken by AEP, ComEd or ETA.[53] The RITELine Companies further state that the Project is being developed to enhance the capability of the regional transmission system to advance national and state energy policies by allowing for the interconnection of approximately 5,000 MW of new renewable energy. In addition, the RITELine Companies state that the Project will take approximately five to six years to complete after obtaining RTEP approval.

43. The RITELine Companies state that from an electrical perspective, the Project is large by any standard. For example, the Project will consist of approximately 420 miles of 765 kV line, which is the highest alternating current voltage in the United States. In addition, the Project will include five 765 kV substations and other appurtenant transmission facilities and must obtain nearly all of the rights-of-way for construction.

44. The RITELine Companies state that the Project will bring reliability benefits to PJM, reduce the cost of delivered power by reducing congestion, and facilitate the integration of substantial wind generation resources that will support state RPS goals. The RITELine Companies state that the Project is a quintessential multi-value transmission project. In addition, the RITELine Companies explain that the value created

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[50] *Id.* P 52-55.

[51] *Id.* P 54.

[52] Transmittal Letter at 33-34.

[53] *Id.* at 34-35.

by this $1.6 billion Project, from a combined wind integration, reliability, and congestion relief perspective, make it one of the most efficient expansion projects ever presented to the Commission for incentive rates.[54]

45. The RITELine Companies argue, among other things, that they face many risks and challenges including: financial challenges; siting challenges, planning process challenges, and industry challenges. First, with regard to financial challenges, the RITELine Companies explain that they are start-up companies with no business history, no credit rating, and no debt repayment history. Therefore, the RITELine Companies state that it will be challenging to secure substantial cash flows to cover ongoing development costs, especially in the early phases of the development. For this reason, the RITELine Companies explain that the incentives requested will significantly enhance the Project's overall financial strength such that the RITELine Companies can obtain the desired BBB credit rating.[55]

46. Second, the RITELine Companies explain that the Project has not been included in the PJM RTEP, and they have not obtained the rights-of-way for the Project or state certification siting approval. The RITELine Companies state that, in Indiana, there is no formal siting process, so they will have to negotiate with numerous individual landowners and, if unsuccessful, initiate individual eminent domain proceedings in each county circuit court. The RITELine Companies note that there is a siting process in Illinois, but they must first obtain approval from the Illinois Commerce Commission to construct the Project along the proposed path, and then, if necessary, initiate eminent domain procedures in the local courts. The RITELine Companies state that these procedures have the potential to increase costs and add delay.[56]

47. Third, the RITELine Companies state that coordinating the Project through the planning process with PJM and its stakeholders will be a major undertaking and require a substantial commitment of time and resources. The RITELine Companies state that PJM does not yet have a formal process in place to evaluate projects like the RITELine Project that bring value through the combination of reliability, wind integration, and economic benefits. In addition, the RITELine Companies state that the PJM RTEP process could

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[54] *Id.* at 36 & n.35 (citing *Pac. Gas & Elec. Co.*, 123 FERC ¶ 61,067, at P 9-11 (2008)).

[55] *Id.* at 36.

[56] *Id.* at 37.

be complicated by virtue of the Commission's NOPR proceeding on transmission planning.[57]

48. Finally, the RITELine Companies state that they will face industry challenges. For example, the RITELine Companies explain that the planning, engineering, design, operation and maintenance of 765 kV bulk transmission lines and substations are complex, requiring special skill sets. In addition, the RITELine Companies explain that the quantity of EHV facilities and equipment required for the Project enhances the riskiness of the Project, as does the need for specialized labor in an increasingly aging labor market, and there are increasing costs of materials.[58]

2. <u>Protests</u>

49. The PSEG Companies argue that the RITELine Companies' request for incentives and the effectiveness of their formula rate must be conditioned on PJM RTEP approval. The PSEG Companies further argue that the PJM RTEP process is the exclusive mechanism for determining whether proposed projects are the right scope, size, and cost and meet PJM's transmission planning needs. The PSEG Companies state that Schedule 6 of the PJM Operating Agreement sets forth a comprehensive regional scheme through which PJM, with input from its stakeholders, plans for the short- and long-term transmission needs of the entire PJM region. The PSEG Companies further state that once a project is submitted into the PJM RTEP process, the project is studied to determine whether it would address system needs for relieving congestion and/or ensuring reliability.[59]

50. The PSEG Companies state that approval by the PJM RTEP is a necessary prerequisite for cost recovery from PJM transmission customers and, therefore, the recovery of any costs of the Project from PJM customers first must be conditioned on having such project approved through the RTEP. Further, the PSEG Companies argue that, to the extent that the Commission finds that the RITELine Project satisfies the Commission's requirements for incentive rates, it may not pre-authorize recovery of any costs associated with the Project from customers pursuant to Schedule 12 of the PJM OATT without conditioning such recovery on the Project first obtaining approval through the approved regional planning processes. More specifically, the PSEG Companies argue that this condition is crucial in the instant case because the RITELine Companies have asked for an effective date 90 days after the filing for its abandonment cost protection and

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[57] *Id.* at 37-38.

[58] *Id.* at 38.

[59] PSEG Companies Protest at 8-9.

related regulatory asset approval, and have made it clear that these protections would apply even if the Project is never endorsed through the PJM planning process. Therefore, without conditioning approval on PJM RTEP, it could later be construed as a retroactive approval of abandonment cost recovery on a regional basis irrespective of whether the regional planners deem the project necessary and appropriate under applicable planning criteria.[60]

3. Answer

51. The RITELine Companies state that, in granting Order No. 679 incentives in advance of regional planning approval in prior cases, the Commission has made clear that the grant of incentives is not intended to pre-judge whether the projects should be included in applicable regional transmission plans. Therefore, the RITELine Companies note that they understand the need to submit their Project for approval in the PJM regional planning process and the regional planning approval is a prerequisite for their formula rate to be included under Schedule 12 of the PJM OATT. Further, the RITELine Companies reiterate that they intend to submit the Project for PJM planning approval in the near future, noting that PJM is considering positive changes to the RTEP process that will facilitate a thorough and fair evaluation of the Project.[61]

4. Commission Determination

52. We find that the RITELine Companies have sufficiently demonstrated a nexus between the considerable risks and challenges they are undertaking to develop and construct the RITELine Project and the incentives they have requested.

53. We find that the RITELine Project is not routine based on the Project's scope, effects, and risks and challenges. First, the scope of the Project is significant, as the 420 mile 765 kV transmission line is estimated to cost approximately $1.6 billion. Second, the Project will permit the integration of approximately 5,000 MW of new wind generation in Illinois, Indiana and western MISO.[62] Third, we find that the RITELine Companies face significant risks and challenges in developing the Project. For example, because Indiana does not have a formal siting process, the RITELine Companies likely will have to obtain rights-of-way for that portion of the Project by negotiating with

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[60] *Id.* at 10-11.

[61] RITELine Companies August 23, 2011 Answer at 6.

[62] *PacifiCorp*, 125 FERC ¶ 61,076, at P 45 (2008) (finding that the "construction or enhancement of transmission facilities designed to provide access to [remote renewable resources on a large-scale] is not routine").

individual landowners and/or initiate eminent domain proceedings in the local circuit court for each county traversed by the Project. Fourth, we consider the risks and challenges associated with using the six-conductor bundle in conjunction with the trapezoidal stranded conductors, as well as other advanced technologies discussed in the RITELine Companies' technology statement, to be relevant to the overall nexus analysis.

54. We note that the RITELine Companies will not be able to recover costs through the PJM tariff without first submitting the Project to PJM for RTEP approval and PJM making a filing with the Commission to include the tariff sheets under PJM's tariff. Moreover, the incentives granted herein are being conditioned on the Project being approved in the PJM RTEP as further discussed elsewhere in this order.

D. Return on Equity Adders

1. Proposal

55. The RITELine Companies request three ROE adders for a total of 250 basis points. First, the RITELine Companies request a 50-basis-point adder for transferring functional control over the Project facilities to PJM. The RITELine Companies state that they will join PJM and granting that 50-basis-point adder is consistent with Commission precedent.[63]

56. Second, the RITELine Companies request a 50 basis point adder for the use of one advanced technology. Specifically, the RITELine Companies are requesting the adder for the use of a six-conductor bundle in conjunction with trapezoidal stranded conductors. The RITELine Companies note that, while one other transmission line uses the six-conductor bundle, no other 765 kV transmission project uses the combination of six-conductors with trapezoidal stranding.[64]

57. Finally, the RITELine Companies request a 150-basis-point adder based on the risks and challenges associated with investing in the Project. The RITELine Companies propose that this risk adder only apply to the Project cost estimate established at the time of RTO approval, unless the cost of the Project is increased due to changes required as a result of the siting process and/or changes specifically directed by PJM. Therefore, the

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[63] Transmittal Letter at 57; Ex. RIT-500 at 84 & n.106 (citing *Pepco Holdings, Inc.*, 121 FERC ¶ 61,169, at P 15-16 (2007)).

[64] Transmittal Letter at 63.

RITELine Companies note that cost increases other than those incurred due to the siting process or to comply with changes required by PJM will not qualify for the risk adder.[65]

2. Protests

58. The Illinois Commission argues that the 150 basis point risk adder proposed by the RITELine Companies is excessive. In *Atlantic Grid Operations*, the Illinois Commission notes that a 150-basis-point adder was proposed by the applicants on the basis of increased risk, but the Commission reduced the risk adder to 100 basis points because the applicants, like the RITELine Companies, also were seeking other rate incentives such as abandonment and regulatory asset. Therefore, the Illinois Commission argues that to the extent that the Commission grants the RITELine Companies the other rate incentives it is seeking in its application, the Commission should set the upper limit of any ROE adders for the RITELine Companies at 100 basis points.[66]

3. Answer

59. The RITELine Companies state that it is appropriate for the Commission to grant their requested ROE adders due to the risks and challenges presented by the Project. In addition, the RITELine Companies argue that the Illinois Commission does not address the RTO adder or the advanced technology adder, but requests that the Commission "set the upper limit of any ROE adders for RITELine at 100 basis points." The RITELine Companies also state that it is appropriate to separately grant the technology adder because they will deploy new technologies. Further, the RITELine Companies argue that the Commission should reject the Illinois Commission's suggestion that the approval of the abandoned plant incentive warrants a reduction in the risk adder or to the adders in general. The RITELine Companies state that the incentive ROE is largely related to the scope and effects of the Project on reliability and congestion.[67] When considered as a whole, the RITELine Companies state, the proposed ROE package achieves a balance between the goals of promoting needed transmission development and the concerns of consumers.

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[65] *Id.* at 8.

[66] Illinois Commission Protest at 6.

[67] RITELine Companies Answer at 6 (citing *Potomac-Appalachian Transmission Highline, L.L.C.*, 133 FERC ¶ 61,152, at P 84 (2010) (*PATH Rehearing Order*)).

4. <u>Commission Determination</u>

60. We will grant the requested 50-basis-point RTO adder, provided that: (1) the Project is included in the PJM RTEP, as discussed above; (2) the RITELine Companies take all the necessary steps to turn over operational control of the Project to PJM; and (3) the RITELine Companies become Participating Transmission Owners. The RITELine Companies state that they will join PJM and relinquish functional control of their transmission operations to PJM.[68] In Order No. 679-A, the Commission stated that it would authorize incentive-based rate treatment for public utilities that are or will continue to be members of Transmission Organizations.[69]

61. We deny the request for a separate advanced technology incentive adder of 50 basis points for the use of a six-conductor bundle in conjunction with trapezoidal stranded conductors in the Project. The Commission has explained that in evaluating a request for a stand-alone advanced technology incentive adder, it reviews record evidence to decide if the proposed technology warrants a separate adder because it reflects a new or innovative domestic use of the technology that will improve reliability, reduce congestion, or improve efficiency.[70] We note that both of the technologies for which the RITELine Companies request a stand-alone advanced technology incentive adder are currently in use, and have been for some time. The RITELine Companies themselves note the use of a six-conductor bundle in AEP's Jackson Ferry-Wyoming 765 kV transmission project, originally introduced in 1990. Furthermore, the use of trapezoidal stranded conductors, and their associated benefits, is well-documented.[71] The RITELine Companies have not demonstrated that the combination of two in use technologies is sufficiently novel or innovative such as to warrant a separate advanced technology ROE adder.[72]

62. Although the six-conductor bundle in conjunction with the trapezoidal stranded conductors does not warrant a separate advanced technology adder, the Commission has

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[68] Ex. RIT-500 at 84-85.

[69] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 86; *see also Green Power Express*, 127 FERC ¶ 61,031 at P 85; *Tallgrass*, 125 FERC ¶ 61,248 at P 58.

[70] *NSTAR Elec. Co.*, 127 FERC ¶ 61,052, at P 27 (2009).

[71] *PacifiCorp*, 125 FERC ¶ 61,076 (2008).

[72] The Commission granted the advanced technology adder in *Atlantic Grid Operations A LLC*, 135 FERC ¶ 61,144 (2011) (*Atlantic Wind*), finding that it used multiple advanced technologies, two of which were first-of-a-kind. *Id.* P 77.

recognized that the risks and challenges of using certain technologies and techniques may be worthy of consideration in the overall nexus analysis.[73] Accordingly, as discussed above, the use of the proposed technologies including the six-conductor bundle in conjunction with trapezoidal stranded conductors in the Project is nevertheless a factor that helps to satisfy the overall nexus analysis.

63. We will grant a 100-basis-point adder for the risks and challenges of the Project, conditioned upon the Project being included in the PJM RTEP, as discussed above. Indeed, the Project faces numerous risks and challenges, including the task of obtaining rights-of-way through several counties without the benefits of a state siting process. In addition, the Project is planned to extend 420 miles, cost $1.6 billion, and integrate approximately 5,000 MW of renewable generation. Moreover, as noted above, we find that the risks and challenges associated with use of advanced technologies discussed in the RITELine Companies' technology statement are relevant to the overall nexus analysis and support our granting of an incentive ROE adder for the Projects' risks and challenges. We find that the RITELine Companies have shown a nexus between such an adder and the size, scope, benefits, and risks and challenges of the Project. However, we are reducing the RITELine Companies' requested 150-basis-point adder to 100 basis points in consideration of the total package of incentives conditionally granted in this order. We find that granting 100 basis points is just and reasonable in light of the other incentives that the Commission is conditionally granting the RITELine Companies herein, some of which reduce certain financial and regulatory risks that the RITELine Companies cite as support for a 150-basis-point incentive ROE adder.[74]

64. In addition, we accept the RITELine Companies' proposal that this incentive adder only apply to the Project cost estimate established at the time of RTO approval, unless the cost of the Project is increased due to changes required as a result of the siting process and/or changes specifically directed by PJM. This commitment will help contain costs to consumers. Accordingly, cost increases other than those incurred due to the siting process or to comply with changes required by PJM would not qualify for this incentive adder.

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[73] *Tallgrass*, 125 FERC ¶ 61,248 at P 59 ("To the extent that the nature of this project requires a more significant application of this technique than is commonly seen, the associated challenges can be incorporated into the overall nexus analysis, but the technique does not, in and of itself, appear to justify a separate advanced technology adder.").

[74] *See, e.g., Atlantic Wind*, 135 FERC ¶ 61,144 at P 78.

E. Return on Equity

1. Proposal

65. The RITELine Companies request a base ROE of 10.7 percent and an overall ROE, with incentives, of 12.7 percent. The RITELine Companies state that an overall ROE of 12.7 percent falls well below the upper end of the zone of reasonableness of 7.2 percent to 15.0 percent.[75] The RITELine Companies note that the midpoint and median in the zone of reasonableness are 11.1 percent and 10.0 percent, respectively.[76]

66. The RITELine Companies assert that they can support an overall ROE of 13.2 percent. Although, the RITELine Companies recognize that the Commission has concluded that the appropriate measure of central tendency for a single utility of average risk is the median, the RITELine Companies propose a base ROE that is between the midpoint and the median.[77] Specifically, the RITELine Companies propose a base ROE of 10.7 percent.[78] The RITELine Companies further note that when their proposed base ROE of 10.7 percent is added to the requested incentives of 250 basis points, the overall ROE would equal 13.2 percent.

67. To arrive at its proposed base ROE, the RITELine Companies state that they relied on the discounted cash flow methodology currently prescribed by the Commission, and applied it to a national proxy group of other electric utilities with comparable investment risks to the Project Developers.[79] The RITELine Companies state that they used a national proxy group, consistent with the approach approved in the *PATH Rehearing Order* where the Commission found that "mere geographic proximity" is not the sole

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[75] Ex. RIT-500 at 6.

[76] *Id.* at 55.

[77] Transmittal Letter at 54-55 & n.63 (citing *S. Cal. Edison Co.*, 131 FERC ¶ 61,020, at P 92 (2010)).

[78] Ex. RIT-500 at 82.

[79] *Id.* at 5 (citing *see, e.g.*, *S. Cal. Edison Co.*, 131 FERC ¶ 61,020; *Bangor Hydro-Elec. Co.*, Opinion No. 489, 117 FERC ¶ 61,129 (2006) (*Bangor Hydro*); *Midwest Indep. Transmission Sys. Operator, Inc.*, 100 FERC ¶ 61,292 (2002), *reh'g denied*, 102 FERC ¶ 61,143 (2003), *modified on other grounds sub nom. Pub. Serv. Comm'n v. FERC*, 397 F.3d 1004 (D.C. Cir. 2005); *S. Cal. Edison Co.*, 92 FERC ¶ 61,070 (2000), *reh'g denied*, 108 FERC ¶ 61,085 (2004)).

basis for inclusion of companies in a proxy group.[80] Therefore, the RITELine Companies used a starting sample of 25 predominantly electric utilities.[81]

68. The RITELine Companies explain that they included companies in their proxy group that: (1) are currently paying dividends; (2) have an S&P corporate credit rating between BBB- and BBB+; (3) have available Value Line data and IBES growth rate data; (4) have not been recently involved in merger and acquisition activity; and (5) have sustainable growth rates below 13.3 percent.[82] The RITELine Companies state that they then excluded six companies from the proxy group because their low-end cost of equity was below or not sufficiently higher than the expected yields on BBB utility bonds, averaging 6.0 percent over the six-month period ending May 2011.[83] In addition, the RITELine Companies excluded ITC Holdings Corp. because its high-end cost of equity estimate was an extreme outlier, consistent with the rationale adopted by the Commission in *Bangor Hydro*.[84]

2. <u>Protests</u>

69. The Illinois Commission argues that the RITELine Companies' DCF analysis is not consistent with the Commission's most recent determinations with respect to the conduct of such tests. Specifically, the Illinois Commission argues that the Commission has used the median as a measure of central tendency in a proxy group for determining an

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[80] Ex. RIT-500 at 29-30 (citing *PATH Rehearing Order*, 133 FERC ¶ 61,152).

[81] RITELine Companies' proposed national proxy group includes: Alliant Energy; Ameren Corp.; American Electric Power Co. Inc.; CenterPoint Energy; Cleco Corp.; CMS Energy; DTE Energy Co.; Edison International; Entergy Corp.; Great Plains Energy; Hawaiian Electric; IDACORP, Inc.; Integrys Energy Group Inc.; ITC Holdings Corp.; Pepco Holdings Inc.; PG&E Corp.; Pinnacle West Capital; Portland General Electric; PPL Corp.; Public Service Enterprise Group; TECO Energy; SCANA Corp.; Sempra Energy; Westar Energy; and Wisconsin Energy Corp. Ex. RIT-503.

[82] Ex. RIT-500 at 29, 42.

[83] Dr. Avera states that he eliminated six companies from the proxy group due to their low-end cost of equity below or not sufficiently above the cost of debt. *Id.* at 40-42. However, Dr. Avera appropriately eliminated seven companies due to their low-end cost of equity not being sufficiently above the cost of debt. Ex. RIT-503.

[84] Ex. RIT-500 at 42 (citing *ISO New England Inc.*, 109 FERC ¶ 61,147, at P 205 (2004)).

appropriate return on equity.[85] Therefore, the Illinois Commission argues that the 10.0 percent base ROE estimated by the use of the median is the more appropriate ROE to be used for the RITELine Project as opposed to the 10.7 percent base ROE recommended by Dr. Avera and proposed by the RITELine Companies.[86]

3. Answer

70. The RITELine Companies argue that, if the Commission approves their requested overall incentive ROE of 12.7 percent with the cost overrun limitation, the significance of the base ROE component is reduced. The RITELine Companies argue that, while the Commission has used the median in single-company cases to determine the appropriate ROE, the Commission should consider Dr. Avera's recommendation that here, for this partnership reflecting investment of subsidiaries of three varied public utility holding companies (AEP, Exelon, and Mid-American Energy) with assets and service territories spanning the nation, the median value for the proxy group alone does not properly reflect the range of ROE values. In addition, the RITELine Companies argue that competition for investor funds is intense and investors are free to invest their funds wherever they choose, and the RITELine Companies can only expect to attract investors if the Commission approves a return commensurate with those from other investments with comparable risk. Therefore, the RITELine Companies argue that they will be better able to compete for capital if the base ROE is 10.7 percent.[87]

4. Commission Determination

71. We find that the 25 companies identified by the RITELine Companies are an appropriate starting point for developing a proxy group that reflects comparable risks. While geographic proximity may be a relevant factor in identifying companies with comparable risks, it is not the sole basis for inclusion of companies in a proxy group.[88] We also find that the corporate credit rating screen that the RITELine Companies used is consistent with Commission precedent.[89]

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[85] Illinois Commission Protest at 4-5 (citing *So. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 87; *Atlantic Wind*, 135 FERC ¶ 61,144 at P 91).

[86] Illinois Commission Protest at 6.

[87] RITELine Companies Answer at 2-4.

[88] *PATH Rehearing Order*, 133 FERC ¶ 61,152 at P 60.

[89] *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188, at P 95 (2008). While the RITELine Companies have proposed Value Line's Safety Rank

(continued)

72. However, we find that the RITELine Companies improperly left in the high-end cost of equity for PPL Corporation when setting the appropriate zone of reasonableness. When we eliminate either the high- or low-end ROE outlier of a company, we also have eliminated the corresponding low- or high-end ROE of that company.[90] Thus, when we eliminate the high-end ROE for PPL Corporation, we determine that the appropriate zone of reasonableness for the RITELine Companies is 7.15 percent to 13.65 percent. The resulting midpoint and median are 10.40 percent and 9.93 percent, respectively.

73. We find it appropriate to grant the RITELine Companies a base ROE of 9.93 percent, which is the corrected median value of the RITELine Companies' DCF analysis. The Commission has found that the median of the DCF analysis is appropriate for establishing the base ROE for an individual utility.[91] For this reason, we reject the alternative methods for establishing a base ROE proposed by the RITELine Companies. This base ROE, combined with the incentive ROE adders that are conditionally granted above, produces an overall ROE of 11.43 percent, which falls within the zone of reasonableness.

74. We direct the RITELine Companies to make a compliance filing within 30 days of the date of this order that revises their formula rate, which is also discussed further below, to reflect the changes to the ROE that are required in this order.

F. Construction Work in Progress

1. Proposal

75. Under Order No. 679 and the Commission's regulations, an applicant must propose accounting procedures that ensure that customers will not be charged for both capitalized allowance for funds used during construction (AFUDC) and corresponding amounts of CWIP in rate base.[92] To satisfy this requirement, the RITELine Companies

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and Financial Strength Rating, we find the use of the corporate credit rating to be sufficient.

[90] *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 58; *Bangor Hydro*, 117 FERC 61,129 at P 54.

[91] *PATH Rehearing Order*, 133 FERC ¶ 61,152 at P 65 (citing *Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,302, at P 8-15 (2004); *Pioneer Transmission, LLC*, 130 FERC ¶ 61,044 (2010) (*Pioneer*); *S. Cal. Edison Co.*, 131 FERC ¶ 61,020 at P 84-93).

[92] 18 C.F.R. § 35.25 (2011).

state that they will use the PowerPlant System to maintain their accounting records for CWIP electric plant assets both during construction and after their projects are placed in-service.[93] The RITELine Companies state the PowerPlant system includes the capability to identify specific work orders or projects that should not be included in the calculation and capitalization of AFUDC. The work orders related to the Project will be identified in the PowerPlant system, and AFUDC will not be calculated on their balances.

76. Public utilities that receive a current return on CWIP through rate base recover this cost in a different period than it would ordinarily be charged to expense under the general requirements of the Uniform System of Accounts (USofA). To promote comparability of financial information between entities, the Commission has required a specific accounting treatment or the use of footnote disclosures to recognize the economic effects of having CWIP in rate base.[94] The RITELine Companies request authorization to use footnote disclosures consistent with disclosures previously authorized by the Commission.[95]

2. <u>Commission Determination</u>

77. We will grant the RITELine Companies' request to include 100 percent of CWIP in rate base, conditioned upon the RITELine Project being approved in the PJM RTEP, as discussed above. The RITELine Companies indicate that their proposed accounting treatment will prevent a double recovery of CWIP and capitalized AFUDC on the same rate base items. We find that the proposed procedures in Exhibit No. RIT-700 demonstrate that the RITELine Companies have accounting procedures and internal controls in place to prevent recovery of AFUDC to the extent the RITELine Companies are allowed to include CWIP in rate base.

78. We will authorize the RITELine Companies to provide footnote disclosures in the notes to the financial statements of its annual FERC Form No. 1 and its quarterly FERC Form No. 3-Q that: (1) fully explain the impact of the CWIP in rate base; (2) include details of AFUDC not capitalized because of the CWIP in rate base for the current year,

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[93] *See* Ex. RIT-700 at 11.

[94] *See, e.g.*, *Am. Transmission Co., LLC*, 105 FERC ¶ 61,388 (2003), *order on reh'g*, 107 FERC ¶ 61,117 (2004); *Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219 (*TrailCo*), *order on reh'g*, 121 FERC ¶ 61,009 (2007); *S. Cal. Edison Co.*, 122 FERC ¶ 61,187, *order on compliance filing*, 125 FERC ¶ 61,337 (2008); *Potomac-Appalachian Transmission Highline*, *L.L.C.*,122 FERC ¶ 61,188 (2008) (*PATH*); *Tallgrass*, 125 FERC ¶ 61,248.

[95] *See* Ex. RIT-700 at 12.

the previous two years, and the sum of all years; and (3) include a partial balance sheet consisting of the Assets and Other Debits section of the balance sheet to include the amount of AFUDC not capitalized because of the inclusion of CWIP in rate base.

G. Abandoned Plant Recovery

1. Proposal

79. The RITELine Companies request that they be permitted to recover 100 percent of prudently incurred costs, including pre-commercial expenses and construction costs, if the Project, or a component thereof, is abandoned due to an event beyond their control. The RITELine Companies note that this treatment will enhance their ability to obtain financing at lower debt costs, while also allowing the RITELine Companies to begin reserving labor and acquiring rights-of-way.[96] In support, the RITELine Companies cite Order No. 679, where the Commission held that recovery of abandoned plant costs is an "effective means to encourage transmission development by reducing the risks of non-recovery of costs."[97]

80. The RITELine Companies also request that the Commission not condition approval of the abandoned plant incentive on the Project's approval in the PJM RTEP. The RITELine Companies assert that the right to seek recovery of abandonment costs is appropriate even if the RITELine Project is not included in the RTEP because there is a significant difference between conceptual projects that are proposed merely based on the location of congestion, and projects that are backed by detailed planning studies. The RITELine Companies note that high-quality projects are subject to opposition in the PJM planning process for a number of reasons. Thus, the RITELine Companies note that the Project faces the risk of PJM evaluating the Project through particular, and sometimes narrow, study parameters. Further, the RITELine Companies explain that despite all the planning efforts expended prior to having the Project considered by an RTO, PJM may not include the Project in the regional plan for factors beyond their control. The RITELine Companies state that these factors support allowing recovery of abandonment costs without obtaining RTEP approvals.[98]

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[96] Ex. RIT-100 at 18.

[97] Transmittal Letter at 41 (citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 163).

[98] Ex. RIT-100 at 20.

2. Protests

81. Both the PSEG Companies and the Illinois Commission argue that any grant of abandonment incentive must be conditioned on PJM RTEP approval. The PSEG Companies also argue that any grant of abandonment should be conditioned on a subsequent section 205 filing. The PSEG Companies argue that only those transmission projects that are approved through the RTEP are eligible for cost recovery from PJM customers through Schedule 12 of the PJM OATT.

82. The Illinois Commission argues that granting this incentive unconditionally may give the RITELine Project a relative advantage over other projects that may address the same transmission needs as the RITELine Project is intended to remedy.[99] In addition, the Illinois Commission argues that granting an abandonment incentive unconditioned by entry into the PJM RTEP may create a risk of "pancaking" abandonment costs upon ratepayers. The Illinois Commission explains that it is not uncommon for multiple transmission projects to be proposed to resolve one set of transmission needs and only the project that provides the lowest cost and most effective manner should be selected. Accordingly, the Illinois Commission states that an unconditional grant of the abandonment incentive could lead to ratepayers paying for abandonment costs for multiple projects that were intended to alleviate a single transmission need.

3. Answer

83. The RITELine Companies argues that protestors' criticism of the RITELine Companies' request to grant an abandonment incentive unconditioned by PJM RTEP approval is inconsistent with Commission policy.[100] Therefore, the RITELine Companies state that contrary to the protestors' assertions, the Commission should not condition approval of the abandonment incentive on approval in the PJM RTEP. The RITELine Companies explain that granting the abandonment incentive unconditioned on PJM RTEP approval will not prejudge the regional RTEP process, or any later 205 filing that may address allocation issues, but will provide a level of certainty that will encourage this important transmission investment. The RITELine Companies also note that they

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[99] Illinois Commission Comments at 8 (citing *Cent. Transmission, LLC*, 135 FERC ¶ 61,145 (2011)).

[100] RITELine Companies August 23, 2011 Answer at 3 (citing *Desert Sw. LLC*, 135 FERC ¶ 61,143, at P 74, n.61 (2011)); RITELine Companies September 1, 2011 Answer at 9 (citing *Desert Sw. LLC*, 135 FERC ¶ 61,143, at P 20 (2011); *Green Power Express*, 127 FERC ¶ 61,031 at P 42; *Green Energy Express*, 129 FERC ¶ 61,165 at P 13; *SoCal Edison*, 129 FERC ¶ 61,246 at P 17; *Ne. Transmission Dev. LLC*, 135 FERC ¶ 61,244, at P 69 (2011)).

commit to making a section 205 filing prior to recovery of any abandoned plant costs, consistent with Commission precedent.

4. Commission Determination

84. We will grant RITELine Companies' request for recovery of 100 percent of prudently incurred costs associated with abandonment of the Project, conditioned upon the Project being included in the PJM RTEP, provided that the abandonment is a result of factors beyond the control of the RITELine Companies, which must be demonstrated in a subsequent section 205 filing for recovery of abandoned plant costs.[101] As we have emphasized in other proceedings, the recovery of abandonment costs is an effective means to encourage transmission development by reducing the risk of non-recovery of costs.[102]

85. We find that the RITELine Companies have demonstrated a nexus between the recovery of prudently-incurred costs associated with abandoned transmission projects and its planned investment. We agree with the RITELine Companies that the Project faces substantial risks outside of the RITELine Companies' control. Approval of the abandonment incentive will both attract financing for the Project, and protect the RITELine Companies from further losses if the Project should be cancelled for reasons outside the RITELine Companies' control. This incentive, however, is conditioned on the Project being included in the PJM RTEP because, as discussed above, we find that such inclusion is necessary for the RITELine Companies to satisfy the threshold requirement of section 219.

86. We will not determine the justness and reasonableness of the RITELine Companies' abandoned plant recovery, if any, until the RITELine Companies seek such recovery in a future section 205 filing.[103] Order No. 679 specifically reserves the prudence determination for the later section 205 filing that every utility is required to make if it seeks abandoned plant recovery.[104] We note that, should the Project be cancelled before it is completed, it is unclear whether the RITELine Companies will have any customers from which to recover its abandonment costs. At such time, the RITELine Companies will be required to demonstrate in its section 205 filing that abandonment was beyond its control, provide for rate authorization consistent with the PJM tariff allowing

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[101] *Id.* P 165-166.

[102] *Id.* P 163.

[103] *Primary Power*, 131 FERC ¶ 61,015 at P 124.

[104] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 165-166.

for recovery of abandonment costs that were prudently-incurred, and propose a rate and cost allocation method to recover the costs in a just and reasonable manner.[105]

H. Regulatory Asset Accounting Treatment

1. Proposal

87. Each RITELine Company seeks authorization to establish a regulatory asset in Account 182.3, Other Regulatory Assets, which they will accrue all costs that are not capitalized and included in CWIP incurred to date and up to the date that charges are assessed to customers under the formula rate. Such costs would include attorney and consultant fees, entity formation costs, administrative expenses, travel expenses, development surveys, and costs to support regional planning activities that are or have been incurred by the RITELine Companies or the Project Sponsors. The RITELine Companies also request authorization to amortize the regulatory assets over five years, beginning in the first year that costs are assessed to customers under the formula rate.

88. In addition, the RITELine Companies seek permission to accrue carrying charges on the regulatory asset balances beginning on the date that the Commission accepts the regulatory asset. The RITELine Companies will utilize the weighted average cost of capital rate to accrue carrying costs. Carrying charges will be recorded by debiting Account 182.3 and crediting Account 421, Miscellaneous Non-Operating Income. Finally, the RITELine Companies state that once charges start flowing under the formula rate, new costs would no longer be added to the regulatory assets. Instead, such new costs would be flowed to customers as they are incurred, in accordance with the formula.

89. The RITELine Companies assert that this incentive is needed because it provides the only means by which they can recover development costs not included in CWIP that they incur before they recover costs under the formula rate. The RITELine Companies also assert that by ensuring the ability to recover these development costs, the regulatory asset incentive enhances credit quality and the ability to obtain financing on more reasonable terms. The RITELine Companies state that in *PATH*, the Commission recognized that the recovery of this incentive would enhance *PATH*'s cash flow, assist with financing, and improve coverage ratios used by rating agencies to determine credit quality.[106] The RITELine Companies also state that in *Green Power Express*, the Commission approved the creation of several regulatory assets that were to correspond

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[105] *See Pioneer*, 130 FERC ¶ 61,044 at P 27; *Green Power Express*, 127 FERC ¶ 61,031 at P 52.

[106] 122 FERC ¶ 61,188 at P 52.

with the various phases of that project (vintage year regulatory asset).[107] Consistent with the rationale underlying that ruling, the RITELine Companies seek authority to create a regulatory asset for each RITELine Company.

2. Protest

90. The Illinois Commission argues that the RITELine Companies should provide greater detail on the costs contained in its proposed regulatory asset, either in this proceeding or in a future section 205 proceeding. Specifically, the Illinois Commission would like to see greater detail with regard to the projected 2011 cost data of $1,324,414 currently posted in the regulatory asset account in the formula rate. With regard to this amount, the Illinois Commission is concerned with whether or not the RITELine Companies are seeking recovery of an appropriate share of the SMART study costs. The Illinois Commission argues that since the RITELine Companies have placed an estimate of costs in this section 205 filing, the RITELine Companies also should at this time provide the details of the review process to ensure that none of the expenses associated with the regulatory asset are unwarranted costs associated with the SMART Study.[108]

91. The Illinois Commission also argues that any carrying costs on the regulatory asset should be at the RITELine Companies' cost of debt, rather than by the weighted average cost of capital sought by the RITELine Companies. The Illinois Commission states that allowing a carrying cost based on debt appropriately balances the interests of the developers and those of the ratepayers. However, the Illinois Commission states that if the Commission elects to allow the carrying costs to include costs associated with equity, the carrying costs should not include any incentive adders to the base ROE.[109]

92. The PSEG Companies argue, to the extent that the Commission finds that the RITELine Companies have adequately demonstrated that they are entitled to establish a regulatory asset for development costs and to amortize such costs, the Commission must condition any recovery of such costs from PJM customers on the Project first being approved through the PJM RTEP.[110]

[107] 127 FERC ¶ 61,031 at P 56, 109.

[108] Illinois Commission Protest at 7.

[109] *Id.* at 7-8.

[110] PSEG Protest at 13.

3. **Answer**

93. The RITELine Companies state that the Commission has previously accepted proposals to establish regulatory assets in order to book non-capital costs incurred prior to the effective date of their formula rates, together with requests to recover costs booked to the regulatory assets over a defined period when their projects are eligible for cost recovery under the applicable or RTO (or independent system operator) OATT.[111] The RITELine Companies state that the regulatory asset incentive is necessary to establish a mechanism for cost recovery, assuming cost recovery is permitted, but does not pre-judge the issue whether any RITELine Project costs are or will ultimately be eligible for cost recovery under the PJM OATT or otherwise.[112]

94. The RITELine Companies state that it is appropriate to accrue carrying charges at the weighted average cost of capital and the Illinois Commission comments provide no reason to require otherwise.[113] The RITELine Companies state that the proposed regulatory asset was based on estimated costs incurred such as attorney and consultant fees, entity formation costs, administrative expenses, travel expenses, development surveys, and costs to support regional planning activities. The RITELine Companies argue that the Commission should dismiss the Illinois Commission's request for further information about these costs because this is not the time for the Illinois Commission to raise such issues. The RITELine Companies argue that the formula itself is the rate and, as such, the formula is the subject of this proceeding, not the inputs therein. The RITELine Companies point out that the appropriate time for the Illinois Commission to raise such questions is through the annual update process, which will provide interested parties the opportunity to submit information requests and file challenges to the costs included in the formula rate.[114]

4. **Commission Determination**

95. The RITELine Companies propose to record pre-construction costs not included in CWIP incurred prior to the effective date of its formula rate as a regulatory asset up to the date that charges are assessed to customers under the formula rate. We find that this

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[111] RITELine Companies August 23, 2011 Answer at 6 (citing *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 at P 84-86; *Green Power Express*, 127 FERC ¶ 61,031 at P 42).

[112] *Id.* at 7.

[113] *Id.* at 8 (citing *Primary Power*, 131 FERC ¶ 61,015 at P 111,117).

[114] *Id.* at 8-9.

incentive is tailored to the RITELine Companies' risks and challenges because this incentive will provide the RITELine Companies with added up-front regulatory certainty and can reduce interest expense, improve coverage ratios, and assist in the construction of the facility. Therefore, we find the RITELine Companies' recovery of pre-construction costs during the construction period to be appropriate, and grant the RITELine Companies' request to establish a regulatory asset for each company, conditioned upon the Project being included in the PJM RTEP.

96. We approve the RITELine Companies' request to accrue a carrying charge from the effective date of the regulatory assets until the regulatory assets are included in rate base.[115] We also authorize the RITELine Companies to amortize each regulatory asset over five years, consistent with rate recovery.[116] Once the RITELine Companies begin to recover the initial regulatory asset in rate base as part of their revenue requirement, the RITELine Companies will earn a return on the unamortized balance of the regulatory asset and, therefore, the RITELine Companies must stop accruing carrying charges on such regulatory asset.[117]

97. Pre-construction costs deferred as a regulatory asset recorded in Account 182.3 only may include amounts that would otherwise be chargeable to expense in the period incurred, are not recoverable in current rates, and are probable for recovery in rates in a different period. Furthermore, the instructions to Account 182.3 require that amounts deferred in this account are to be charged to expense concurrent with the recovery of the amounts in rates. If rate recovery of all or part of the costs deferred in Account 182.3 is later disallowed, the disallowed amount shall be charged to Account 426.5, Other Deductions, in the year of disallowance.

98. If the RITELine Project is cancelled before completion, it is unclear whether the RITELine Companies will have any customers from which to recovery its regulatory asset. In addition, while this order provides the RITELine Companies with the ability to record pre-construction costs as a regulatory asset, the RITELine Companies must make a section 205 filing to demonstrate that the pre-construction costs are just and reasonable. The RITELine Companies will have to establish that the costs included in the regulatory

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[115] *See, e.g.*, *Green Power Express*, 127 FERC ¶ 61,031 at P 60; *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 at P 84.

[116] *See, e.g.*, *Green Power Express*, 127 FERC ¶ 61,031 at P 59; *Primary Power*, 131 FERC ¶ 61,015 at P 117.

[117] *See, e.g.*, *Green Power Express*, 127 FERC ¶ 61,031 at P 60; *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 at P 84.

asset are costs that would have otherwise been chargeable to expense in the period incurred. Parties will be able to challenge these costs at that time.

I. Total Package of Incentives

1. Proposal

99. The RITELine Companies state that they have tailored the requested incentives to the large investment and the special risks and challenges associated with the Project. The RITELine Companies note that although the requested incentives are designed to alleviate a different risk, they were selected as a package to work together in order to ensure that the Project is completed in a timely manner. In addition, the RITELine Companies state that the package of incentives will improve the likelihood that the RITELine Companies will be able to attract capital to participate in the Project on terms beneficial to customers who ultimately will bear cost responsibility for the Project.[118]

2. Commission Determination

100. As noted above, in Order No. 679-A, the Commission clarified that its nexus test is met when an applicant demonstrates that the total package of incentives requested is tailored to address the demonstrable risk or challenges faced by the applicant. The Commission noted that this nexus test is fact-specific and requires the Commission to review each application on a case-by-case basis. Consistent with Order No. 679,[119] the Commission has, in prior cases, approved multiple rate incentives for particular projects.[120] This is consistent with our interpretation of section 219 authorizing the Commission to approve more than one incentive rate treatment for an applicant proposing a new transmission project, as long as each incentive is justified by a showing that it satisfies the requirements of section 219 and that there is a nexus between the incentives proposed and the investment made. We find that the total package of incentives that we are approving for the RITELine Companies is tailored to address the risks or challenges faced by the RITELine Companies.

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[118] Transmittal Letter at 47-49.

[119] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 55.

[120] *Atlantic Wind*, 135 FERC ¶ 61,144 at P 127 (internal citations omitted) (approving ROE at the upper end of the zone of reasonableness and 100 percent abandoned plant recovery), *order on reh'g*, 118 FERC ¶ 61,042 (2007); *Duquesne Light Co.*, 118 FERC ¶ 61,087 at P 55, 59, 61 (granting an enhanced ROE, 100 percent CWIP, and 100 percent abandoned plant recovery); *see also Cent. Me.*, 125 FERC ¶ 61,182 at P 100 (granting both abandonment and ROE incentives).

J. Formula Rate

1. Proposal

101. The RITELine Companies propose to implement a formula rate and protocols which they state is similar to formula rates that the Commission has previously approved.[121] The RITELine Companies explain that their proposed formula rate is designed to track increases and decreases in actual costs and projected capital additions. The proposed formula rate contains a true-up mechanism that is implemented at the end of each rate period that will ensure that any deviation from actual costs during the rate period is reflected in an adjustment (with interest) to the annual transmission revenue requirement in the subsequent period. In addition, the RITELine Companies state that the formula rate employs Commission-approved ratemaking methodologies and contains sufficient specificity to operate without discretion in its implementation. Therefore, the RITELine Companies state that the formula rate and protocols are just and reasonable, and will encourage the construction and timely placement into service of needed transmission infrastructure.[122]

102. The RITELine Companies state that they will not assess charges to customers under the formula rate until either the Project is included in the RTEP or the Commission issues an order on the allocation of charges. In addition, the RITELine Companies state that upon inclusion of the facilities in the PJM RTEP, there will be an additional section 205 filing to designate the RITELine Companies' formula rate and protocols as a numbered Attachment H of the PJM OATT.[123]

103. The RITELine Companies explain that the formula rate is designed to calculate the annual transmission revenue requirement (ATRR) by forecasting the values that will populate the formula rate by May 1, and calculate a true-up of the forecasted values when the actual data becomes available. Any difference between the forecasted ATRR and actual ATRR will be added to the following year's ATRR. The RITELine Companies

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[121] Ex. RIT-600 at 6 (citing *Am. Transmission Co*., 97 FERC ¶ 61,139 (2001); *Commonwealth Edison Co.*, 122 FERC ¶ 61,030 (2008); *Am. Elec. Power Serv. Corp.*, 124 FERC ¶ 61,306 (2008); *Am. Elec. Power Transmission Co.*, 135 FERC ¶ 61,066 (2011); *Tallgrass*, 132 FERC ¶ 61,114.

[122] Transmittal Letter at 49-50 (citing Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 386).

[123] *Id.* at 50.

explain that the true-up mechanism will ensure that neither the customers nor the transmission owners are harmed if the forecasted ATRR differs from the actual ATRR.[124]

104. The RITELine Companies state that the formula rate provides for the recovery of a return on rate base (and associated taxes), taxes other than income taxes, depreciation expenses, and other operation and maintenance expenses, less revenue credits. In addition, the RITELine Companies state that for transmission and general plant balances, it uses the average of 13-monthly balances, whereas for accumulated deferred income taxes, land held for future use, materials and supplies and prepayments, it uses the average of the beginning and end-of-year balances. The RITELine Companies further state that because they are not subject to federal income taxes as a limited liability company, any tax obligations incurred through their operations will be passed through to and reported on the tax returns of their corporate parents. However, for ratemaking purposes, the RITELine Companies state that they are treated as a corporation and receive an income tax allowance. The RITELine Companies state that the proposed treatment of taxes is consistent with Commission practice.[125]

105. The RITELine Companies state that the formula rate includes a stated rate for post-employment benefits other than pensions, depreciations rates, ROE, and capital structure during the construction phase of the Project. The RITELine Companies note that these values only may be changed pursuant to a section 205 or 206 filing. However, the RITELine Companies explain that they will not assess charges to customers until the Project is included in the PJM RTEP, at which time the formula rate and protocols will be resubmitted by PJM in the appropriate PJM tariff database.[126]

106. The RITELine Companies' proposed protocols provide that, in May of each year, the companies will populate the rate formula template using the data contained in the FERC No. Form 1 for the prior calendar year for RITELine Illinois and RITELine Indiana, plus projected capital additions for the current year to establish the ATRR. The RITELine Companies explain that they will also calculate the difference between the prior calendar year's estimated ATRR and the actual costs reported in the FERC Form No. 1 and will reflect the difference (with interest) in the estimated ATRR that will go into effect on June 1. The RITELine Companies state that they will submit this information annually as an informational filing in this docket and also will post an excel

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[124] *Id.* at 50-51.

[125] *Id.* at 51 (citing *Green Power Express LP*, 135 FERC ¶ 61,141, at P 110 (2011)).

[126] *Id.* at 51-52.

sheet of a populated formula rate on the PJM website, or, prior to the inclusion of the Project in the RTEP, on the website of the RITELine Companies.[127]

107. The RITELine Companies explain that the protocols govern the specific procedures for notice, requests for information, review and challenges to the annual update. Specifically, the protocols allow interested parties 150 days to review and to submit preliminary written challenges to specific items in the formula rate. In addition, interested parties will have 120 days to serve reasonable information requests on the RITELine Companies, and the RITELine Companies will make reasonable efforts to respond to such requests within 15 business days. Further, if a preliminary challenge is made, the protocols provide that interested parties will have a 21-day period to resolve the dispute regarding the formula inputs. If the interested parties are unable to resolve the dispute, they have an additional 21 days to file a complaint with the Commission. The RITELine Companies note that parties retain their rights under sections 205 and 206 of the FPA, without regard to the formal review process. The RITELine Companies state that, consistent with Commission precedent, the proposed protocols do not limit a customer's or the Commission's rights with respect to challenges to the inputs into the formula rate in accordance with section 206 of the FPA.[128]

2. Protest and Comments

108. The PSEG Companies argue that the establishment of formula rates for the RITELine Project is premature absent approval and determination of cost allocation pursuant to PJM's RTEP process. Specifically, the PSEG Companies argue that until PJM actually: (1) approves a project into the RTEP; and (2) makes a filing at FERC identifying the beneficiaries for the project, the cost allocation for a proposed RTEP project will remain unknown. In addition, the PSEG Companies note that the projects that PJM ultimately approves as part of the RTEP may not match the projects that were proposed. Therefore, the PSEG Companies note that it is questionable how formula rates for any "proposed" RTEP project could take effect prior to the completion of the RTEP process, in which cost allocation will be determined. For these reasons, the PSEG Companies argue that approval and effectiveness of any formula rate must be conditioned, at a minimum, on PJM RTEP approval. Alternatively, the PSEG Companies state that the Commission should consider dismissing such rate filings without prejudice

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[127] *Id.* at 52-53.

[128] *Id.* at 53 & n.61 (citing *Tampa Elec. Co.*, 133 FERC ¶ 61,023, at P 61 (2010); *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 at P 113).

for being premature until the cost allocation for the Project has been determined through the PJM RTEP process.[129]

109. The Illinois Commission expresses several concerns related to the RITELine Companies' proposed formula rate review protocol, which the Illinois Commission claims could constrain the right of ratepayers to challenge formula rate inputs. First, the Illinois Commission recommends deleting "or upon receipt of an order from FERC on the allocation of the charges for the RITELine Project" from section 2.1 because the RITELine Companies have not explained the reason for including this language or its meaning. The Illinois Commission argues that, if the language is intended to apply to the recovery of abandoned plant costs, the Commission should require the RITELine Companies to make a filing under section 205 to demonstrate that any abandoned plant costs were prudently incurred and propose a just and reasonable rate and cost allocation methodology to recover those costs.[130]

110. Second, the Illinois Commission requests that the Commission direct the RITELine Companies to delete "provided, however, that the initial burden to raise a substantial doubt as to the prudence of any new cost or expenditure shall be the Interested Party raising the challenge" from section 3.c.vi. The Illinois Commission argues that this language is unnecessary because section 5.c properly reflects the rights of parties under sections 205 and 206 of the FPA and section 3.c.vi does not.

111. Third, the Illinois Commission recommends that modifying the language in section 3.f to allow the review of related components in the formula rate, rather than restricting review to the single component. The Illinois Commission argues that changes made to the value of one of the stated elements in the formula rate may merit review of other elements that are related to the stated element and the proposed protocol would prohibit such review.

112. Fourth, the Illinois Commission requests that the RITELine Companies clarify what "reconciliation made under [s]ection 4" provided in section 3.g.vii is referring to. The Illinois Commission suggests that changing this language to "changes made pursuant to the Annual Review Process under [s]ection 4" would make sense.

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[129] PSEG Protest at 13-14.

[130] Similar to *Green Power Express*, the Illinois Commission notes that the RITELine Companies may not have any customers from which to recover any costs that it incurs. Illinois Commission Comments at 10 (citing *Green Power Express*, 127 FERC ¶ 61,031 at P 52).

113. Fifth, the Illinois Commission requests the time period for review under section 4.a be extended from 150 days to 180 days. The Illinois Commission states that this revision would be consistent with the period of review under Commonwealth Edison's protocol specified in the PJM Tariff.[131] Similarly, the Illinois Commission requests that time period for information requests under section 4.b be expanded from 125 days to 150 days, which also is consistent with Commonwealth Edison's protocol.[132]

114. Sixth, the Illinois Commission requests that the Commission direct the RITELine Companies to add language to section 6 to make any changes to data points that happen as a result of revisions made on RITELine Companies' own initiative to FERC Form No. 1 be subject to the challenge and review process set forth in section 4. Furthermore, the Illinois Commission requests clarification to what "This reconciliation mechanism" in section 6 is referring to because section 6 does not appear to describe any "reconciliation" mechanism.

115. Finally, the Illinois Commission proposes two further revisions to the protocol to correct apparent typographical errors in sections 1 and 3.e.[133]

3. <u>Answer</u>

116. The RITELine Companies state that they will agree with several changes suggested by the Illinois Commission and propose to make such changes in a compliance filing. Specifically, the RITELine Companies agree to correct the typographical errors identified in sections 1 and 3.e, extend the deadlines as requested in 4.a and 4.b, and make the change suggested in section 6.

117. With regard to the other concerns raise by the Illinois Commission, the RITELine Companies respond as follows. First, with regard to section 2.1, the RITELine Companies clarify that "or upon receipt of an order from FERC on the allocation of charges" is intended to apply to the recovery of abandoned plant costs. The RITELine Companies note that, if the Project is abandoned, they will need to make a subsequent 205 filing and the quoted language is intended to provide for the situation where the Commission provides for an allocation of the abandoned plant costs.

118. Second, with regard to section 3.c.vi and the suggested language deletion by the Illinois Commission, as stated above, the RITELine Companies argue that under Commission precedent, a utility's costs are presumed prudent and a person challenging

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[131] *Id.* at 11 (citing PJM, OATT, Attachment H-13B (2.0.0) § 2(a)).

[132] *Id.* (citing PJM, OATT, Attachment H-13B (2.0.0), § 2(b)).

[133] Illinois Commission Comments at 10.

such costs has the burden of producing evidence that raises a serious doubt as to prudence. The RITELine Companies argue that section 3.c.vi accurately captures the Commission's standard for prudence challenges. Additionally, the RITELine Companies note that nothing in 3.c.vi alters their ultimate burden of demonstrating the justness and reasonableness of the rate resulting from the application of the formula rate. The RITELine Companies further note that section 5.c of the protocols clarifies this and provides the following: "the RITELine Companies shall bear the burden . . . of providing that they have correctly applied the terms of the Formula Rate . . . . Nothing herein is intended to alter the burdens applied by the Commission with respect to prudence challenges."

119. Third, with regard to section 3.f, the RITELine Companies state that this section is intended to provide for single-issue rate filings with respect to only those narrowly stated inputs to the formula rate. The RITELine Companies argue that this is consistent with Commission precedent and given that nothing in the protocols limits a party's rights under section 205 or 206 of the FPA, it is not necessary to implement the suggested changes.

120. Fourth, with regard to section 3.g.vii, the RITELine Companies clarify that "any changes to the data inputs made as a result of the reconciliation made under Section 4" requires the RITELine Companies to provide, as part of the Annual Update, information concerning the resolution of any preliminary challenges.

121. Fifth, with regard to section 4.b, the RITELine Companies clarify that "whether the RITELine Companies have properly calculated the Annual Update under review (including any corrections pursuant to Section 4)" allows interested parties to submit information requests concerning whether the RITELine Companies properly reflected any revisions to the formula rate inputs that were required due to the resolution of any preliminary challenges.

122. Sixth, with regard to section 6, the RITELine Companies clarify that the quoted language above refers to the incorporation of any changes made pursuant to section 6 into the next year's annual update.

4. **<u>Commission Determination</u>**

123. The RITELine Companies cannot assess charges to customers until the Project is included in the PJM RTEP and PJM includes the formula rate and protocols in its tariff. We will accept the RITELine Companies' proposal to implement a formula rate with modifications to the protocols, to become effective October 17, 2011, as requested, as discussed herein.

124. The Commission has accepted the use of formula rates by a number of utilities in the PJM region, both those utilizing prior-year FERC Form No. 1 data to calculate rates

for the upcoming year,[134] as well as those utilizing projected costs, as the RITELine Companies propose to do.[135] In each case, the fundamental process remains the same: Rates are estimated for the following year and data regarding such rates is provided to customers with sufficient time to review and challenge the rates before the Commission, if necessary, before they are implemented. Once the actual costs are known from that year's FERC Form No. 1, those costs are trued-up to the rates charged over the past year and any over-collections are returned to customers with interest. These mechanisms allow the utility to recover its costs in a timelier manner while protecting customers from inflated rates through the true-up process. The RITELine Companies' proposal is consistent with this structure, and is, therefore, accepted.[136]

125. We direct the RITELine Companies to revise their formula rate protocols within 30 days in the compliance filing ordered below. First, we direct the RITELine Companies to correct the typographical errors identified by the Illinois Commission in sections 1 and 3.e. Second, we direct the RITELine Companies to extend the agreed upon deadlines in sections 4.a and 4.b. We note that the attachment contained a typographical error in section 4.a. Specifically, the attachment reads "one hundred eight [sic] (180)" versus "one hundred eighty (180)." Therefore, we direct the RITELine Companies to revise section 4.a to correct this typographical error to "one hundred eighty (180)" as part of the compliance filing ordered below. Third, we direct the RITELine Companies to make the agreed upon addition in section 6 of the protocols.

126. With regard to section 2.1, as noted above, the RITELine Companies will need to make a subsequent section 205 filing in order to recover abandonment costs. Interested parties shall have the right to comment on the prudence of such costs and the RITELine Companies' proposal to recover them.

127. With regard to section 3.c.vi, we agree with the RITELine Companies that the initial burden to raise a substantial doubt as to the prudence of any new cost or expenditure included in the annual update is upon the interested party raising the challenge. In addition, we note that section 5.c provides that the RITELine Companies bear the burden of proving that they have correctly applied the terms of the formula rate and that they followed the applicable requirements. Further, section 5.c states that nothing in the protocols is intended to alter the burdens applied by the Commission with

[134] *Baltimore Gas & Elec. Co.*, 115 FERC ¶ 61,066 (2006); *Duquesne Light Co.*, 118 FERC ¶ 61,087.

[135] *PATH*, 122 FERC ¶ 61,188.

[136] *Pub. Serv. Elec. & Gas Co.*, 124 FERC ¶ 61,303, at P 11 (2008).

respect to prudence challenges. Therefore, we find that section 3.c.vi is just and reasonable.

128. With regard to section 3.f, we agree with the Illinois Commission and find that customers should be able to challenge related elements of the formula rate or protocols. Therefore, we direct the RITELine Companies to submit a compliance filing within 30 days of the date of this order to revise the formula rate protocols in section 3.f to state "shall not open review of unrelated components" consistent with the Illinois Commission's proposal, as discussed above. In addition, we accept the RITELine Companies' clarifications with regard to sections 3.g.vii, 4.b, and 6.

129. Finally, we direct the RITELine Companies to use the interest rate from Attachment 5 of 6.83 percent as the cost of debt versus the requested 8.39 percent and 8.33 percent for RITELine Indiana and RITELine Illinois, respectively, until debt is issued. After issuing debt, we direct the RITELine Companies to update the cost of debt in the formula rate appropriately. Therefore, we direct the RITELine Companies to submit a compliance filing within 30 days of the date of this order to reflect the calculated interest rate as the cost of debt verses the requested cost of debt for RITELine Indiana and RITELine Illinois.

K. Hypothetical Capital Structure

1. Proposal

130. The RITELine Companies propose to reflect in its formula rate a hypothetical capital structure of 45 percent debt and 55 percent equity until long-term financing is obtained and the Project begins commercial operation. The RITELine Companies state that this capital structure will not only result in a more predicable and steady cash flow stream from formula rate revenues, but it will also support the RITELine Companies' efforts to obtain at least BBB investment grade quality. In addition, the RITELine Companies state that once long-term financing has been secured and the Project assets have been placed in-service, they will target an actual capitalization of approximately 45 percent debt and 55 percent equity, and the actual capitalization will be used in the formula rate.[137]

2. Commission Determination

131. We grant the RITELine Companies' request to use a hypothetical capital structure consisting of 45 percent debt and 55 percent equity until such time as any portion of the Project achieves commercial operation, conditioned upon the Project being included in

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[137] Transmittal Letter at 58-59.

the PJM RTEP, as discussed above. Once any portion of the Project achieves commercial operation, the RITELine Companies will use their actual capital structure. The RITELine Companies have demonstrated a nexus between the requested incentive and the risks and challenges faced by the Project. Specifically, the RITELine Companies must raise significant levels of debt and equity capital to develop and construct the Project. Approval of the hypothetical capital structure will: (1) reduce the effects on rates resulting from swings in the actual capital structure due to varying cash demands during the construction phase; (2) prove a more consistent cash flow during the construction phase; and (3) contribute to receiving and maintaining an investment grade credit rating profile during the financing phase of the project, thus lowering the overall cost of capital.[138]

L. **Income Taxes**

132. RITELine Illinois and RITELine Indiana will be pass-through entities for federal income tax purposes and will not be liable for the payment of any income taxes.[139] Although the RITELine Companies, as limited liability companies, will not be subject to federal income tax, the tax obligations incurred through their operations will be passed through to and reported on the tax returns of theirs corporate parents.[140] For ratemaking purposes, the Commission treats pass-through entities, such as the RITELine Companies, as though they are corporations and allows them to receive an income tax allowance for the tax liability ultimately paid by their parents.[141] RITELine Illinois and RITELine Indiana state that they will maintain their books of account based on the Commission's USofA as if they were a taxable corporation,[142] including the income tax accounting

[138] *See, e.g.*, *PATH*, 122 FERC ¶ 61,188 at P 55; *see also* Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 93 (finding that hypothetical capital structures "can be an appropriate ratemaking tool for fostering new transmission in certain relatively narrow circumstances").

[139] *See* Ex. RIT-700 at 7.

[140] Transmittal Letter at 51.

[141] *See Green Power Express*, 127 FERC ¶ 61,031 at P 110; *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 at P 120; *Tallgrass*, 125 FERC ¶ 61,248 at P 84.

[142] *See* Ex. RIT-700 at 8.

requirements of the USofA.[143] Thus, we find that RITELine Illinois and RITELine Indiana's income tax accounting proposal is consistent with Commission policy.[144]

M. Requested Waivers

133. The RITELine Companies request waiver of section 35.13 of the Commission's regulations, including waiver of the full Period I-Period II data requirements and waiver of the requirements to determine if, and to the extent to which, a proposed change constitutes a rate increase based on Period I-Period II rates and billing determinants. The RITELine Companies state that good cause exists for these waivers, as explained in its application. Additionally, the RITELine Companies request "waiver of any applicable regulations to allow the filing to take effect in the manner described."[145]

134. We will grant the RITELine Companies' request for waiver of section 35.13 requirements, consistent with our prior approval of formula rates.[146]

The Commission orders:

(A) The RITELine Companies' request for CWIP, abandonment, and regulatory asset incentives, and their request for an additional ROE adder for the risks and challenges of the Project, reduced to 100 basis points, and a 50 basis points ROE adder for membership in an RTO are hereby conditionally granted, as discussed in the body of this order.

(B) The RITELine Companies' request for an advanced technology adder is hereby denied, as discussed in the body of this order.

(C) The RITELine Companies' request for the use of a hypothetical capital structure is hereby granted, as discussed in the body of this order.

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[143] Part 101 of the Commission's regulations sets forth the accounting requirements for income tax, including: General Instructions No. 18, and Accounts 190, 236, 281, 282, and 283. 18 C.F.R. pt. 101 (2011)

[144] *PATH*, 122 FERC ¶ 61,188 at P 157.

[145] Transmittal Letter at 68-69.

[146] *Commonwealth Edison Co. and Commonwealth Edison Co. of Ind., Inc.*, 119 FERC ¶ 61,238, at P 94 (2007), *order on reh'g*, 122 FERC ¶ 61,037, *order on reh'g*, 124 FERC ¶ 61,231 (2008); *Okla. Gas & Elec. Co.*, 122 FERC ¶ 61,071, at P 31 (2008).

(D) The RITELine Companies' proposed formula rate and protocols are hereby conditionally accepted for filing, subject to the compliance filing ordered below, to become effective October 17, 2011, as discussed in the body of this order.

(E) The RITELine Companies' request for waivers of section 35.13 of the Commission's regulations is hereby granted, as discussed in the body of this order.

(F) The RITELine Companies are hereby directed to submit a compliance filing within 30 days of the date of this order that: (1) revises their formula rate to reflect the required changes to their ROE; (2) contains revisions to the protocols for the formula rate; and (3) updates the cost of debt in the formula rate, as discussed in the body of this order.

(G) The RITELine Companies are hereby directed to submit a compliance filing within 30 days of the date of approval of the Project in the PJM RTEP, informing the Commission of such approval.

By the Commission. Commissioner Spitzer is not participating.
Commissioner Moeller dissenting in part with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

RITELine Illinois, LLC	Docket Nos.	ER11-4069-000
RITELine Indiana, LLC		ER11-4070-000

(Issued October 14, 2011)

MOELLER, Commissioner, *dissenting in part*:

Now is not the time for this Commission to begin retreating from its incentive policy on needed transmission lines. Yet I question whether we are sending that message with a 50 basis-point reduction in the 150 basis-point incentive for risks and challenges. This order conditions all of its incentives on approval by the planning process established in PJM (the RTEP process). Thus, this project will not be built unless it is needed.

The recent impact of the new TrAIL power line illustrates how needed transmission can transform the competitiveness of not only the power grid, but of the nation in general. The TrAIL project, approved in the PJM planning process and entering service this year, will undoubtedly have an impact in reducing congestion costs across PJM. In fact, based on the data in PJM's report on its RTEP Plan for year 2010, it appears that the billion-dollar TrAIL power line, in conjunction with other transmission improvements across PJM, will be reducing congestion costs by about one-billion dollars in year 2013.[1] This means that power lines that will be paid for by consumers in installments over forty or more years could pay for themselves within a few years.

Philip D. Moeller
Commissioner

[1] See Section 13 of the 2010 RTEP Plan, and in particular, figure 13.2. Available on PJM's website at: http://www.pjm.com/documents/reports/rtep-report.aspx

Document Content(s)

	Equity Ratio	Return	Weighted Return
Maritime Link	30%	9.10%	2.7300%
Alberta Tx	37%	8.75%	3.2375%
Hydro One	40%	9.20%	3.6800%
US (RITELine)	55%	9.93%	5.4615%

QUÉBEC **RÉGIE DE L'ÉNERGIE**

D-2010-147	R-3724-2010	26 novembre 2010

PRÉSENTS :

Louise Rozon
Richard Carrier
Lise Duquette
Régisseurs

Gazifère Inc.
Demanderesse

et

Intervenants dont les noms apparaissent ci-après

Décision relative à la Phase 2 – Taux de rendement – et à la Phase 4 – Plan d'approvisionnement pour l'exercice 2011 et tarifs à compter du 1er janvier 2011

Demande relative au renouvellement du mécanisme incitatif, à la fermeture réglementaire des livres pour la période du 1er janvier 2009 au 31 décembre 2009, à l'approbation du plan d'approvisionnement pour l'exercice 2011 et à la modification des tarifs de Gazifère Inc. à compter du 1er janvier 2011

Intervenants :

- Association coopérative d'économie familiale de l'Outaouais (ACEFO);
- Association des consommateurs industriels de gaz (ACIG);
- Fédération canadienne de l'entreprise indépendante (section Québec) (FCEI);
- Groupe de recherche appliquée en macroécologie (GRAME);
- Stratégies énergétiques et Association québécoise de lutte contre la pollution atmosphérique (S.É./AQLPA);
- Union des municipalités du Québec (UMQ).

TABLE DES MATIÈRES

1. INTRODUCTION

1.1 DEMANDE

[1] Le 4 mars 2010, Gazifère Inc. (Gazifère ou le distributeur) dépose à la Régie de l'énergie (la Régie), en vertu des articles 31 (1) (5), 32, 34, 48, 49, 72 et 73 de la *Loi sur la Régie de l'énergie*[1] (la Loi), de l'article 1 du *Règlement sur les conditions et les cas requérant une autorisation de la Régie de l'énergie*[2] et de l'article 4 du *Règlement sur la teneur et la périodicité du plan d'approvisionnement*[3], une demande relative à l'approbation du renouvellement de son mécanisme incitatif, à la fermeture réglementaire de ses livres pour la période du 1er janvier 2009 au 31 décembre 2009, à l'approbation de son plan d'approvisionnement pour l'exercice 2011, à la modification de ses tarifs et à l'approbation de certaines autres conditions auxquelles le gaz naturel sera fourni, transporté ou livré aux consommateurs à compter du 1er janvier 2011.

[2] Le 16 mars 2010, la Régie rend la décision D-2010-028, par laquelle elle avise qu'elle procédera à l'examen de cette demande en quatre phases. La première phase porte sur le renouvellement du mécanisme incitatif et sur les taux d'amortissement, la deuxième sur le taux de rendement sur l'avoir de l'actionnaire, la troisième sur la fermeture réglementaire des livres et la quatrième sur le plan d'approvisionnement et la modification des tarifs.

[3] La présente décision porte sur les demandes de Gazifère visées par les deuxième et quatrième phases (Phases 2 et 4).

1.2 HISTORIQUE DE LA PHASE 2

[4] Dans sa décision D-2010-028, la Régie fixe la procédure et l'échéancier de traitement des sujets visés par la Phase 2.

1 L.R.Q., c. R-6.01.
2 (2001) 133 G.O. II, 6165.
3 (2001) 133 G.O. II, 6037.

[5] Le 26 mars 2010, la Régie modifie l'échéancier de traitement de la Phase 2 pour tenir compte de certaines contraintes du distributeur[4].

[6] Le 7 avril 2010, la Régie rend la décision D-2010-037, par laquelle elle accorde le statut d'intervenant à l'ACEFO, l'ACIG, la FCEI, le GRAME, S.É./AQLPA et l'UMQ et établit les budgets de participation pour les Phases 1 et 2. Elle accueille favorablement la proposition des groupes représentant les consommateurs de se regrouper pour déposer une preuve sur la question du taux de rendement dans le cadre de la Phase 2.

[7] Le 10 juin 2010, les intervenants déposent leur preuve[5].

[8] L'audience a lieu les 31 août, 1er et 2 septembre 2010 à Montréal.

[9] Le 3 septembre 2010, Gazifère dépose ses réponses aux engagements qu'elle a souscrits lors de l'audience du 1er septembre 2010[6].

[10] Les demandes visées par la Phase 2 sont prises en délibéré à compter du 3 septembre 2010.

1.3 HISTORIQUE DE LA PHASE 4

[11] Le 22 juillet 2010, Gazifère dépose son plan d'approvisionnement pour l'exercice 2011[7].

[12] Le 30 août 2010, Gazifère dépose une demande amendée qui porte sur les sujets visés par la Phase 4 ainsi que les pièces à son soutien[8].

[13] Le 2 septembre 2010, la Régie rend la décision D-2010-118, par laquelle elle fixe la procédure et l'échéancier de traitement de cette demande.

4 Pièces A-2 et B-2.
5 Pièces C-1-15 et C-2-13.
6 Pièce B-38.
7 Pièce B-29.
8 Pièce B-35.

[14] Le 17 septembre 2010, la Régie rend la décision D-2010-125, par laquelle elle établit les budgets de participation des intervenants pour la Phase 4.

[15] Le 13 octobre 2010, les intervenants déposent leur preuve[9].

[16] L'audience a lieu les 1er, 2 et 4 novembre 2010 à Montréal.

[17] Le 5 novembre 2010, Gazifère dépose ses réponses à un engagement qu'elle a souscrit lors de l'audience[10].

[18] Les demandes visées par la Phase 4 sont prises en délibéré à compter du 5 novembre 2010.

1.4 CONCLUSIONS RECHERCHÉES

[19] Les conclusions recherchées par Gazifère pour la Phase 2, selon la demande du 4 mars 2010, sont les suivantes :

> « ***PHASE II - TAUX DE RENDEMENT***
>
> ***APPROUVER****, pour l'année témoin 2011, un taux de rendement sur l'avoir de l'actionnaire de 11,25 %;*
>
> ***APPROUVER*** *la formule proposée par Gazifère pour l'établissement du taux de rendement sur l'avoir de l'actionnaire, dans le rapport déposé comme pièce GI-4, document 1, pour application à compter de l'année témoin 2012.* »

[20] Les conclusions recherchées par Gazifère pour la Phase 4, selon la demande amendée du 30 août 2010, sont les suivantes :

9 Pièces C-1-32, C-3-25, C-4-14, C-5-16 et C-6-17.
10 Pièce B-54.

« ***PHASE IV - PLAN D’APPROVISIONNEMENT ET MODIFICATION DES TARIFS***

ACCUEILLIR *la demande d’approbation du plan d’approvisionnement;*

APPROUVER *le plan d’approvisionnement de Gazifère pour l’exercice 2011, présenté à la pièce GI-33, document 1, tel que prévu à l’article 72 de la Loi;*

ACCUEILLIR [la] *demande amendée de modification des tarifs;*

MODIFIER *les tarifs de la Demanderesse, à compter du 1er janvier 2011, de façon à ce qu’ils puissent générer les revenus de distribution établis suite à l’application de la formule approuvée par la Régie dans le cadre de la phase I du présent dossier;*

APPROUVER *les paramètres utilisés et le calcul fait par Gazifère pour établir les revenus requis de distribution pour l’année témoin 2011;*

APPROUVER *les charges réglementaires ainsi que les charges liées au PGEÉ et à la quote-part versée à l’Agence de l’efficacité énergétique, prévues par la Demanderesse pour l’année témoin 2011, telles que présentées à la pièce GI-35, document 2.3, et* **AUTORISER** *la Demanderesse à inclure ces montants dans l’établissement du revenu requis de l’année témoin 2011 à titre d’exclusion ;*

APPROUVER *les soldes des comptes différés relatifs aux charges réglementaires, aux programmes d’efficacité énergétique et à la quote-part versée à l’Agence de l’efficacité énergétique (compte d’écart 2009), tels que présentés à la pièce GI-35, document 2.3;*

AUTORISER *la Demanderesse à inclure les soldes de ces comptes différés dans l’établissement du revenu requis de l’année témoin 2011 à titre d’exclusion;*

AUTORISER *la Demanderesse à inclure les montants liés à ses propositions de mécanisme incitatif axé sur le PGEÉ et d’introduction d’un CASEP dans l’établissement du revenu requis de l’année témoin 2011 à titre d’exclusion;*

APPROUVER *les modalités, objectifs et budgets volumétrique et monétaire associés aux programmes du PGEÉ de Gazifère pour la période du 1er janvier au 31 décembre 2011;*

AUTORISER *les projets d’extension et de modification du réseau de la Demanderesse détaillés à la pièce GI-34, document 2, à l’exclusion de tout projet dont le coût est égal ou supérieur au seuil de 450 000 $ énoncé dans le Règlement sur les conditions et les cas requérant une autorisation préalable de la Régie de l’énergie et qui exigerait une autorisation préalable de la Régie en vertu de l’article 73 de la Loi et dudit règlement.*

***APPROUVER** le taux de gaz perdu établi par Gazifère pour l'année témoin 2011.* »

[21] Lors de l'audience du 1er novembre 2010, Gazifère indique que le revenu requis de distribution pour l'année témoin 2011 sera mis à jour pour refléter la décision que la Régie rendra dans le cadre de la Phase 4. Elle précise que le taux de rendement qui sera autorisé par la Régie dans le cadre de la Phase 2 pour l'année témoin 2011 aura un impact sur le revenu additionnel requis de distribution mais ne modifiera pas les autres conclusions qu'elle recherche[11].

2. TAUX DE RENDEMENT (PHASE 2)

2.1 CADRE JURIDIQUE

[22] En vertu de l'article 31 de la Loi, la Régie réglemente les activités de distribution de gaz naturel au Québec, dont celles pour lesquelles Gazifère détient un droit exclusif.

[23] Lorsque la Régie fixe un tarif de gaz naturel, ce dernier doit être juste et raisonnable [article 49 (7)]. Le tarif qu'elle fixe doit permettre l'atteinte, par le distributeur, d'un rendement raisonnable sur la base de tarification [article 49 (3)]. De plus, la Régie doit procéder à cet exercice en s'assurant du respect des ratios financiers [article 49 (5)]. Les tarifs ne doivent toutefois pas prévoir des taux plus élevés ou des conditions plus onéreuses qu'il n'est nécessaire pour permettre, notamment, de couvrir les coûts de capital et d'exploitation, de maintenir la stabilité du distributeur et le développement normal de son réseau de distribution ou d'assurer un rendement raisonnable sur la base de tarification (article 51).

[24] Dans sa décision D-2009-156[12], la Régie précisait son rôle et ses pouvoirs lorsqu'elle fixe un taux de rendement pour un distributeur. Après avoir passé en revue la jurisprudence élaborée au cours des ans par les tribunaux supérieurs canadiens et américains, la Régie rappelait les trois critères qui ont été historiquement reconnus par les

[11] Pièce A-49-1, page 18.
[12] Dossier R-3690-2009.

régulateurs comme fondant la norme du rendement raisonnable, soit les critères de l'investissement comparable, de l'intégrité financière et de l'attraction des capitaux. La norme du rendement raisonnable et les trois critères la fondant n'ont fait l'objet d'aucun débat en la présente instance.

[25] Selon ces trois critères, pour être raisonnable, un taux de rendement sur le capital doit :

- être comparable à celui que rapporterait le capital investi dans une autre entreprise présentant un risque analogue (critère de l'investissement comparable);
- permettre à l'entreprise d'attirer des capitaux additionnels à des conditions raisonnables (critère de l'effet d'attraction de capitaux);
- permettre à l'entreprise réglementée de préserver son intégrité financière (critère de l'intégrité financière).

[26] Dans sa décision D-2009-156, la Régie concluait que ces critères font consensus et qu'ils peuvent servir de guide dans l'exercice de sa juridiction à l'égard de la fixation d'un taux de rendement raisonnable.

[27] Par ailleurs, dans cette même décision, la Régie considérait que son devoir est de déterminer un taux de rendement raisonnable et que la méthode qu'elle utilise relève de sa discrétion. À cet égard, la Régie rappelait que les tribunaux ont reconnu la grande latitude et la discrétion des organismes de régulation dans le choix de la meilleure méthode pour fixer un taux de rendement raisonnable sur l'avoir de l'actionnaire.

2.2 MODÈLES UTILISÉS POUR ÉTABLIR LE COÛT DE L'AVOIR PROPRE

[28] Les experts entendus lors de l'audience utilisent des approches et des modèles différents pour recommander un taux de rendement raisonnable sur l'avoir de l'actionnaire pour Gazifère.

[29] L'expert de Gazifère, Mme Kathleen McShane, applique, pour l'évaluation du coût de l'avoir propre, plusieurs modèles de type « prime de risque », dont le modèle d'évaluation des actifs financiers (MÉAF), le modèle d'actualisation des flux monétaires (AFM) avec une et deux variables et enfin, le modèle basé sur l'historique de la prime de risque d'un distributeur repère. Elle termine son exposé avec une estimation du rendement

requis obtenue à l’aide de la méthode directe du modèle AFM en ayant recours à plusieurs variantes.

[30] L’expert de l’ACIG, le Dr Laurence D. Booth, utilise le MÉAF ainsi qu’un modèle à deux facteurs portant sur la prime de risque du marché et la prime de risque des obligations de long terme du Canada.

[31] Le MÉAF est représenté par l’équation suivante :

$$K = R_f + \beta^*(R_m - R_f)$$

[32] Cette équation représente le taux de rendement (K) qu’un investisseur s’attend à recevoir d’un placement effectué sur un titre comportant un certain risque. Le rendement attendu pour ce titre (K) correspond au rendement qui pourrait être obtenu par un investissement sans risque (R_f), auquel est ajoutée une prime de risque. Cette prime, propre au titre évalué, est proportionnelle au risque du marché (R_m - R_f). Ce dernier est estimé par la différence entre le rendement généré par un portefeuille de titres diversifié (R_m) et celui d’un investissement sans risque (R_f). La relation proportionnelle entre le risque du marché et le risque associé au titre est exprimée par le facteur bêta (β).

[33] Le taux de rendement sur l’avoir de l’actionnaire résultant des calculs du Dr Booth en vertu des modèles qu’il utilise est de 7,75 %, avant la prise en compte des frais d’émission et de l’ajustement pour le risque de Gazifère. Le Dr Booth recommande pour Gazifère un taux de rendement autorisé sur l’avoir de l’actionnaire de 8,5 %.

[34] Le taux de rendement sur l’avoir de l’actionnaire résultant des calculs de Mme McShane en vertu du MÉAF est de 9,25 % lors du dépôt de sa preuve et de 8,71 % lors de sa mise à jour à l’audience, avant la prise en compte des frais d’émission et de l’ajustement pour le risque de Gazifère.

[35] Le modèle prime de risque basé sur le modèle AFM selon une ou deux variables (méthode indirecte) vise à estimer la prime de risque des sociétés réglementées à partir d’un échantillon de sociétés américaines. Selon le modèle AFM, le coût de l’avoir propre mensuel est estimé à partir de la somme de deux éléments : d’une part, le consensus des analystes financiers à l’égard des prévisions de croissance normalisée à long terme des profits et, d’autre part, le rendement attendu du dividende. La prime de risque, quant à

elle, est égale à la différence entre la moyenne mensuelle du coût de l'avoir propre de l'échantillon et le rendement à la fin du mois correspondant aux obligations de 30 ans du gouvernement américain[13].

[36] En appliquant le modèle AFM, Mme McShane fait deux régressions linéaires pour ajuster la prime de risque résultant de son estimation. Dans un premier temps, elle utilise le taux de rendement des obligations de 30 ans du gouvernement des États-Unis comme variable explicative. Dans un deuxième temps, elle ajoute une seconde variable explicative correspondant à l'écart de rendement entre les obligations à long terme des sociétés réglementées américaines de cote de crédit A et les obligations de 30 ans du gouvernement des États-Unis.

[37] Le taux de rendement sur l'avoir de l'actionnaire résultant des calculs de Mme McShane en vertu de ce modèle est de 9,40 % lors du dépôt de sa preuve et de 9,10 % lors de sa mise à jour à l'audience, avant la prise en compte des frais d'émission et de l'ajustement pour le risque de Gazifère.

[38] Le modèle basé sur l'historique de la prime de risque des sociétés réglementées se calcule à partir des rendements réalisés des sociétés réglementées canadiennes et américaines. Mme McShane utilise un rendement moyen réalisé de 11,5 % pour ces sociétés réglementées. Par la suite, elle soustrait de ce résultat la prévision à long terme du taux de rendement des obligations de 30 ans du gouvernement du Canada, qui est de 5,25 %. La prime de risque des sociétés réglementées qu'elle en déduit est donc de 6,25 %. Enfin, elle additionne cette prime de risque à sa prévision du taux de rendement des obligations de 30 ans du gouvernement du Canada pour l'année 2011, qu'elle établit à 4,75 %.

[39] Le taux de rendement sur l'avoir de l'actionnaire résultant des calculs de Mme McShane en vertu de ce modèle est de 11 % lors du dépôt de sa preuve et de 10,40 % lors de sa mise à jour à l'audience, avant la prise en compte des frais d'émission et de l'ajustement pour le risque de Gazifère.

[13] Pièce B-1, GI-4, document 1, page 51.

[40] Comme alternative aux méthodes de type « prime de risque », Mme McShane estime de façon directe le rendement attendu à l'aide du modèle AFM. Ce modèle indique que le prix P d'une action est égal à la valeur actualisée au taux k de ses dividendes futurs qui croissent indéfiniment au taux g.

Le modèle AFM s'exprime donc par l'équation :

$$P = D_1/(k\text{-}g)$$

ou, écrit d'une autre façon :

$$k = D_1 /P + g$$

où

k = taux de rendement sur l'avoir de l'actionnaire
D_1 = dividende versé à l'année 1
P = prix au marché de l'action
g = taux de croissance des dividendes

[41] Le taux de rendement sur l'avoir de l'actionnaire résultant des calculs de Mme McShane en vertu de ce modèle est de 10 % lors du dépôt de sa preuve et est demeuré le même lors de sa mise à jour à l'audience, avant la prise en compte des frais d'émission et de l'ajustement pour le risque de Gazifère.

[42] Mme McShane conclut que, selon les modèles de type « prime de risque » et AFM, le taux de rendement sur l'avoir de l'actionnaire résultant de ses calculs est de 10 % lors du dépôt de sa preuve et de 9,70 % lors de sa mise à jour à l'audience, avant la prise en compte des frais d'émission et de l'ajustement pour le risque de Gazifère.

[43] Mme McShane recommande pour Gazifère un taux de rendement autorisé sur l'avoir de l'actionnaire de 11,25 % lors du dépôt de sa preuve et de 10,95 % lors de sa mise à jour à l'audience.

[44] La Régie s'étonne du résultat produit par le modèle basé sur l'historique de la prime de risque d'un distributeur repère proposé par Mme McShane. En effet, la Régie constate un écart important entre le résultat de 6,25 % pour la prime de risque d'un distributeur repère alors que, dans l'application du MÉAF présenté par l'experte, cette prime est de 4,56 % sur la base d'une prime de risque du marché de 6,25 % et d'un bêta de 0,68.

[45] Toutefois, en audience[14], Mme McShane précise que la Régie doit regarder ces tests individuellement et reconnaître qu'ils apportent une perspective différente de ce que le rendement pourrait être. Par ailleurs, Mme McShane précise que si le MÉAF fonctionne parfaitement, alors la prime de risque des sociétés réglementées devrait être inférieure à la prime de risque du marché. La Régie juge néanmoins que la prime de risque d'un distributeur repère, produit à partir du modèle basé sur l'historique de cette prime de risque, est élevée.

[46] Quant au modèle AFM, la Régie est d'avis que ce modèle comporte certaines difficultés pratiques, notamment quant à l'estimation du taux de croissance des dividendes des titres choisis. La Régie note que l'application de ce modèle, que ce soit par la méthode directe ou indirecte, se fait à partir de données américaines uniquement. La Régie note également que l'application de la méthode indirecte du modèle AFM se fait à partir des rendements réalisés des sociétés de gestion américaines qui incluent des actifs réglementés et non réglementés.

[47] **En regard de la preuve soumise, la Régie retient principalement, aux fins de sa décision, le modèle d'évaluation des actifs financiers.** Il s'agit de l'approche retenue par la Régie dans ses décisions antérieures. De plus, ce modèle est reconnu et utilisé tant dans les milieux de la finance que par la majorité des experts témoignant devant les organismes de réglementation.

[48] L'utilisation de ce modèle comporte cependant, dans le contexte actuel, des difficultés que la Régie aborde plus en détails dans les sections suivantes.

[14] Pièce A-35-2, pages 27 à 30.

[49] Par mesure de prudence, comme aucun modèle ne peut reproduire parfaitement à lui seul les attentes de rendement des investisseurs, la Régie prend en considération, aux fins de son appréciation du taux de rendement sur l'avoir de l'actionnaire de Gazifère, les résultats des autres modèles de type « prime de risque » et AFM de Mme McShane ainsi que du modèle multifacteur utilisé par le Dr Booth. La Régie traite plus en détails de ce sujet à la section 2.2.6.

2.2.1 TAUX SANS RISQUE

[50] L'application du MÉAF requiert l'établissement d'un taux sans risque (R_f) auquel s'ajoutera la prime de risque de l'entreprise. Selon la pratique usuelle dans la réglementation canadienne, le taux sans risque utilisé est celui des obligations de long terme de 30 ans du gouvernement du Canada.

[51] Mme McShane révise son taux sans risque lors de l'audience à 4,15 % pour l'application des modèles de type « prime de risque »[15]. Ce taux est établi sur la base du Consensus Fococasts du mois d'août 2010[16].

[52] Le Dr Booth appuie son jugement sur une hypothèse de croissance économique normale et un taux d'inflation de 2 %. Il retient un taux sans risque de 4,5 %.

[53] Enfin, selon la méthode d'établissement habituelle découlant du Consensus Forecasts du mois d'octobre 2010 et de l'écart entre le rendement des obligations du gouvernement du Canada de 10 ans et de 30 ans pour le mois précédent, le taux sans risque se situe à 3,644 %, tel que déposé par Gazifère[17].

[54] **Sur la base de la preuve au dossier, la Régie établit le taux sans risque dans une fourchette variant de 4,15 % à 4,50 %.**

[15] Ce taux était établi à 4,7 % lors du dépôt de sa preuve.
[16] Consensus Forecasts, 9 août 2010.
[17] Pièce B-45, GI-30, document 5, page 1. Cette pièce a été déposée le 18 octobre 2010.

2.2.2 PRIME DE RISQUE DU MARCHÉ

[55] Le MÉAF requiert l'établissement de la prime de risque du marché ($R_m – R_f$) en fonction de laquelle sera établie la prime de risque d'une entreprise réglementée type, communément appelée un distributeur repère.

[56] Selon Mme McShane, la prime de risque du marché se situe à 6,75 %. Elle est d'avis que la prime de risque sera plus élevée que la moyenne historique, compte tenu que les rendements futurs des obligations seront plus faibles que ceux observés historiquement et que les rendements futurs, dans le marché boursier, seront semblables à ceux observés historiquement. Enfin, selon cette experte, les effets de la crise financière dans les marchés des capitaux seraient chose du passé[18].

[57] Le Dr Booth présente des estimations de la prime de risque du marché à partir de séries de données couvrant des périodes débutant en 1926 et en 1957 et se terminant en 2009. Il établit ses estimations à partir des moyennes arithmétique et géométrique et de la méthode des moindres carrés ordinaires. Il recommande une prime de risque du marché de 5,5 %. Sa recommandation est corroborée par une étude du professeur Fernandez. Les résultats de cette étude ont été établis à partir des opinions d'un échantillon de professeurs de finance, d'analystes financiers et de dirigeants de sociétés[19].

[58] Le Dr Booth considère la reprise économique fragile et les écarts de crédit supérieurs à ce qu'ils devraient être dans un cycle économique normal. Il recommande un ajustement de 50 points de base pour les effets liés à la crise financière.

[59] Dans sa décision D-2009-156[20], la Régie, aux fins d'estimer la prime de risque du marché, utilisait des proportions égales pour les données canadiennes et pour les données américaines. En tenant compte de la preuve au présent dossier, la Régie utilise la même approche.

[60] La Régie maintient l'établissement de la prime de risque du marché sur la base de la moyenne arithmétique des rendements observés sur les marchés. Le choix des périodes de référence pour établir la prime de risque soulève cependant certains enjeux. En effet, la

[18] Pièce A-35-1, page 32.
[19] Pièce C-2-13, preuve du Dr Booth, pages 40 à 42.
[20] Dossier R-3690-2009, page 62.

moyenne calculée peut différer sensiblement selon l'année de départ et de fin et la série de données retenues. Dans ce contexte, la Régie choisit d'accorder une prépondérance aux moyennes de longues périodes.

[61] **Sur la base de la preuve au dossier, la Régie établit la prime de risque du marché, avant prise en considération des effets de la crise financière, dans une fourchette variant de 5,50 % à 5,75 %.**

[62] En ce qui a trait aux effets de la crise financière, la Régie retient le point de vue du D^{r} Booth selon lequel la reprise économique est fragile et que les écarts de crédit sont encore supérieurs à ce qu'ils devraient être dans un cycle économique normal.

[63] Compte tenu de la preuve au dossier et de l'objectif de maintenir un accès au marché à des conditions raisonnables, la Régie juge qu'il y a lieu d'octroyer, dans les circonstances du présent dossier, un ajustement pour tenir compte des effets de la crise financière.

[64] **Par conséquent, la Régie établit, pour tenir compte des effets de la crise financière, une majoration de la prime de risque du marché dans une fourchette variant de 0,50 % à 1 %.**

2.2.3 RISQUE D'UN DISTRIBUTEUR REPÈRE

[65] Le D^{r} Booth et Mme McShane présentent une estimation du risque d'un distributeur repère, soit une société de service public présentant un niveau de risque faible. Le risque d'un distributeur repère est mesuré par le facteur bêta (β). Celui-ci représente le différentiel de risque entre la société repère et le marché en général.

[66] L'établissement du bêta comporte des difficultés importantes. Ces difficultés ont trait, entre autres, à l'établissement d'un échantillon de référence représentatif du risque des sociétés réglementées ainsi qu'à l'obtention de séries de données valables pour procéder à une estimation robuste.

[67] Mme McShane présente un bêta ajusté se situant dans une fourchette de 0,65 à 0,70 calculé à partir de différents tests. Elle présente également un bêta brut de 0,44 calculé par Bloomberg à partir d'un échantillon de sociétés canadiennes.

[68] Le D^r^ Booth présente divers estimés basés sur les données récentes, mais souligne qu'il est nécessaire de faire preuve de jugement et propose donc d'établir le bêta d'un distributeur repère sur la base de la moyenne historique, qu'il évalue entre 0,45 et 0,55.

[69] Mme McShane utilise des bêtas ajustés pour tenir compte des recherches empiriques montrant la tendance des bêtas à converger vers 1. Le D^r^ Booth soutient plutôt que les bêtas des sociétés réglementées convergent vers leur propre moyenne et non vers 1.

[70] Après examen, la Régie maintient la position exprimée dans ses décisions antérieures[21] voulant que les bêtas des sociétés réglementées convergent vers la moyenne qui leur est propre et non vers celle du marché qui, par définition, est égale à un 1.

[71] **Sur la base de la preuve au dossier, la Régie établit le bêta d'un distributeur repère dans une fourchette de 0,50 à 0,55.**

2.2.4 RISQUE DE GAZIFÈRE

[72] Le risque d'affaires de Gazifère par rapport au risque d'un distributeur repère a fait l'objet d'un examen approfondi en 1999. Dans le cadre du présent dossier, la Régie réexamine ce risque.

[73] Un témoin de Gazifère, Mme Vandal-Parent, mentionne, lors de l'audience, que les liens d'affaires créés avec les entrepreneurs en construction pourraient s'effriter en raison de la retraite potentielle de ces derniers. En effet, la croissance soutenue qu'a connue Gazifère ces dernières années dans le secteur résidentiel serait le résultat, entre autres, des

[21] Décision D-2009-156, dossier R-3690-2009; décision D-2007-116, dossier R-3630-2007; décision D-2003-93, dossier R-3492-2002 Phase 1 et décision D-2002-95, dossier R-3401-98.

liens d'affaires entretenus par Gazifère avec ces entrepreneurs. Si ceux-ci devaient prendre leur retraite, Gazifère pourrait voir sa croissance limitée[22].

[74] Selon Mme McShane, le risque d'affaires pour l'investisseur est l'incertitude liée à la réalisation du rendement sur son capital ainsi qu'à la récupération de son capital.

[75] Mme McShane indique que Gazifère est une petite société réglementée pour laquelle aucun comparable direct n'existe. Elle utilise son jugement pour quantifier le risque additionnel de Gazifère par rapport au risque d'un distributeur repère.

[76] Elle présente un tableau des décisions des régulateurs canadiens. Elle admet la circularité de cette comparaison mais soutient que cette information demeure utile aux fins de son analyse.

[77] Par la suite, Mme McShane discute du concept d'isolement. Ce concept permet d'établir, sur une base théorique, quel serait le coût des capitaux de Gazifère si celle-ci était une société totalement indépendante. Cette approche repose sur le principe économique des coûts d'opportunité où le coût de chaque ressource, capital compris, est celui qui correspond à ses alternatives. Il en découle que le coût des capitaux propres est équivalent au coût d'opportunité pour les investisseurs, un coût ajusté selon le risque, peu importe l'identité de ces investisseurs. Ainsi, les facteurs pertinents dont on doit tenir compte pour établir le coût du capital de Gazifère sont les alternatives offertes aux investisseurs ainsi que les risques et les rendements associés à ces alternatives. Selon elle, en raison de sa petite taille, Gazifère ne pourrait obtenir une cote de crédit plus élevée que BBB.

[78] À partir de ce concept d'isolement, elle utilise le MÉAF et le modèle AFM pour établir une fourchette entre 50 et 80 points de base de risque additionnel pour une société réglementée de cote BBB par rapport à un distributeur repère de cote A.

[79] Mme McShane s'appuie également sur une étude d'Ibbotson Associates pour estimer le risque additionnel d'une petite société. Cette étude démontre que les petites sociétés ont des bêtas plus élevés que les grandes sociétés. Selon cette étude, l'écart entre les bêtas des petites et moyennes sociétés devraient être de 0,32. Au total, le risque additionnel associé à une petite société est d'environ 200 points de base. Il faut noter,

[22] Pièce A-35-1, page 19.

cependant, que cette étude porte sur l'ensemble des sociétés et non uniquement sur les sociétés réglementées.

[80] En conclusion, Mme McShane recommande une prime de risque additionnelle de 50 points de base par rapport à un distributeur repère.

[81] L'ACIG indique que la preuve ne démontre pas un risque accru particulièrement élevé pour Gazifère, surtout par rapport à ce qu'il était en 1999. Les preuves respectives de l'expert et de l'analyste de l'intervenante tendent à démontrer que ce risque est largement atténué.

[82] En effet, selon l'analyse de l'ACIG, plusieurs facteurs démontrent que le risque d'affaires de Gazifère est réduit comparativement à 1999. L'intervenante note la nouvelle composition de la clientèle et le développement de l'économie de service dans la région de la Capitale nationale du Canada en relation avec la réduction de la dépendance de Gazifère envers le secteur industriel.

[83] Selon l'intervenante, Gazifère exploite sa franchise de distribution dans un environnement économique favorable et supérieur à la moyenne. De plus, Gazifère a démontré une très bonne capacité à excéder son rendement autorisé, même pendant la récente crise financière.

[84] L'ACIG note également que la composition de la clientèle de Gazifère est constituée à 93 % de clients qui utilisent le gaz naturel pour le chauffage de l'espace et de l'eau et qui ne peuvent aisément passer à une autre source d'énergie. Ces clients sont captifs et plus difficiles à perdre que des clients industriels interruptibles qui ont la capacité d'avoir recours à des sources d'énergie alternatives. De plus, la composition de sa clientèle actuelle rend le distributeur moins dépendant envers les clients industriels qui représentent maintenant seulement 6 % de ses revenus, incluant 4,5 % pour le secteur des pâtes et papiers.

[85] L'ACIG constate que la situation concurrentielle de Gazifère, en raison du prix actuel du gaz naturel, est avantageuse par rapport à l'huile à chauffage. La situation concurrentielle de Gazifère s'est également améliorée depuis 1999 face à l'électricité. En effet, un gel des tarifs d'électricité était en cours en 1999 et a perduré jusqu'en 2004. Or, depuis, il y a eu des hausses régulières des tarifs d'électricité. Prospectivement, en raison des besoins d'investissements du réseau de distribution et de transport d'électricité ainsi

que des coûts d'approvisionnement plus élevés, les tarifs d'électricité devraient continuer à augmenter. De plus, l'intervenante remarque que l'approche commerciale d'Hydro-Québec dans le marché de la construction est maintenant moins agressive que par le passé.

[86] Également, l'ACIG mentionne que la réduction des volumes par client en raison, notamment, de mesures d'efficacité énergétique, n'est aucunement préjudiciable à Gazifère, puisque cela a pour effet de réduire la facture totale pour chaque client. Selon l'ACIG, la facture totale étant moins élevée, chaque client est plus enclin à demeurer au gaz naturel qu'à se tourner vers des sources d'énergie alternatives.

[87] L'ACIG ajoute que le mécanisme incitatif de Gazifère ne crée aucun risque additionnel à court terme. Cette constatation s'appuie, notamment, sur la capacité de Gazifère d'excéder son rendement autorisé pendant la récente crise financière.

[88] Enfin, le D^{r} Booth, comme l'intervenante, conclut à une légère réduction du risque d'affaires de Gazifère depuis 1999. Le D^{r} Booth recommande une prime de risque additionnelle de 25 points de base par rapport à un distributeur repère.

[89] La Régie évalue le risque global de Gazifère supérieur à la moyenne, notamment en raison de sa taille et de la concurrence de l'électricité au Québec. Cependant, elle tient compte, dans son appréciation, de la couverture plus étendue de ces mêmes risques par des comptes de frais reportés.

[90] La Régie juge que le risque de Gazifère ne s'est pas modifié significativement depuis la décision D-99-09[23], bien qu'il demeure supérieur à celui d'un distributeur repère. **Sur la base de la preuve au dossier, la Régie évalue que le risque plus élevé justifie un ajustement à la hausse, par rapport à la prime de risque d'un distributeur repère, de l'ordre de 25 à 50 points de base.**

[23] Dossier R-3406-98.

2.2.5 FRAIS D'ÉMISSION ET AUTRES COÛTS D'ACCÈS AUX MARCHÉS DES CAPITAUX

[91] Selon Mme McShane, ces frais comprennent trois éléments, soit les frais d'émission, un coussin pour les conditions de marché non anticipées et le principe de maintenir la valeur au marché des actifs au-dessus de la valeur aux livres. Elle recommande 75 points de base pour ces frais.

[92] Le D^r Booth recommande d'ajouter 50 points de base à son estimé du rendement requis pour l'actionnaire, pour tenir compte des frais d'émission et des effets de dilution. Un tel ajustement serait compatible avec la pratique appliquée par plusieurs régulateurs.

[93] L'ACIG mentionne que le concept de Mme McShane pour ces frais est plus large que celui utilisé traditionnellement. De plus, l'intervenante souligne que ce concept plus large inclut des éléments plus ou moins abstraits qui font appel à un jugement de valeur, par exemple un coussin pour les conditions de marché non anticipées.

[94] La Régie juge que les éléments historiquement utilisés pour établir les frais d'émission et autres coûts d'accès aux marchés des capitaux sont suffisants. Elle rejette la proposition de Mme McShane qui repose sur un concept plus large que ce que la Régie a exprimé dans ses décisions précédentes sur ce sujet.

[95] Dans le dossier de Gaz Métro traité l'an dernier, les frais d'émission ont fait l'objet d'un examen détaillé. Dans sa décision D-2009-156, la Régie a jugé qu'une provision pour frais d'émission et autres frais d'accès aux marchés se situant dans une fourchette de 30 à 40 points de base constituait une compensation suffisante. Cette compensation a été établie après avoir examiné les coûts réels des émissions chez Gaz Métro depuis 1993.

[96] Contrairement au cas de Gaz Métro qui émet des titres sur les marchés pour obtenir des capitaux propres, dans le cadre du présent dossier la Régie doit plutôt établir pour Gazifère un estimateur de ces frais. Elle procède donc sur une base théorique, à partir de la preuve au dossier, plutôt que sur une base de coûts réellement encourus.

[97] **Conséquemment, la Régie établit pour Gazifère la provision pour frais d'émission et autres frais d'accès aux marchés des capitaux à 50 points de base.**

2.2.6 RÉSULTATS DES AUTRES MODÈLES

[98] Selon la Régie, le MÉAF demeure le modèle de référence le plus approprié pour servir de guide dans la détermination d'un taux de rendement raisonnable sur l'avoir de l'actionnaire.

[99] Cependant, il est aussi admis par tous les experts qu'aucun modèle ne peut, à lui seul, représenter correctement les attentes des investisseurs dans toutes les circonstances et dans toutes les phases des cycles économiques et financiers. En conséquence, la Régie juge nécessaire de prendre en considération les résultats produits par les autres modèles présentés par les experts.

[100] Par ailleurs, la Régie rappelle que, dans sa décision D-2007-116[24], elle mentionnait que l'application du MÉAF présentait une difficulté particulière lorsque la détermination du rendement dans un dossier intervient dans une période où les taux courants des obligations gouvernementales s'écartent de façon significative du taux moyen de longue période. La prime de risque étant calculée sur de longues périodes et représentant la différence entre la moyenne arithmétique des rendements du marché et de ceux des obligations gouvernementales, cette prime est donc représentative des conditions qui prévalent sur cette même période. La Régie concluait qu'un ajustement s'imposait lorsque les conditions du marché obligataire s'éloignent de cette moyenne.

[101] **Compte tenu de la preuve au présent dossier, la Régie juge qu'un ajustement de l'ordre de 25 à 50 points de base par rapport aux résultats du modèle d'évaluation des actifs financiers est justifié dans les circonstances.**

2.2.7 COMPARAISON AVEC LES DISTRIBUTEURS AMÉRICAINS

[102] Afin de vérifier la validité des tests qu'elle propose, Mme McShane applique ces tests sur un échantillon d'entreprises de distribution. Pour être incluses dans l'échantillon, ces entreprises doivent émettre des titres transigés sur les marchés. Elles doivent également présenter un risque similaire au distributeur repère. Selon Mme McShane, il n'est pas possible d'utiliser un échantillon de sociétés réglementées canadiennes aux fins

[24] Dossier R-3630-2007, page 28.

d'estimation du coût du capital[25]. En effet, selon elle, les sociétés réglementées canadiennes sont très différentes les unes des autres et, par conséquent, ne peuvent servir aux fins de comparaison pour une société réglementée en particulier ou pour l'industrie dans son ensemble.

[103] À cette fin, elle utilise un échantillon de sociétés américaines pour valider les résultats de ces tests. Selon elle, aucun ajustement n'est nécessaire, puisque l'environnement réglementaire, légal, fiscal et comptable canadien est similaire à celui prévalant aux États-Unis. Cependant, elle reconnaît que l'application réglementaire n'est pas identique[26].

[104] Pour effectuer les différents tests aux fins d'estimation du coût du capital, Mme McShane utilise les données fournies par Standard and Poor's. En audience, elle indique que ces données sont basées sur un échantillon de sociétés américaines qui ont des activités réglementées et non réglementées. Elle indique également qu'elle ne connaît pas la relation exacte entre les rendements réalisés attribuables uniquement aux activités réglementées des sociétés américaines de son échantillon et les rendements autorisés[27].

[105] Selon l'ACIG, dans la décision D-2009-156 la Régie a formulé de sérieuses réserves quant à l'usage d'un échantillon de distributeurs américains ou de rendements accordés à des distributeurs américains à titre de comparables aux fins de la détermination du taux de rendement d'un distributeur repère.

[106] L'ACIG réitère que le présent dossier n'a toujours pas permis d'identifier les taux de rendement réalisés attribuables uniquement aux activités réglementées des sociétés américaines par opposition aux rendements des sociétés de gestion qui les chapeautent, pas plus d'ailleurs que la comparaison entre les taux de rendement réalisés et les rendements autorisés.

[107] L'ACIG indique que Mme McShane a admis qu'il y a une volatilité importante des rendements réalisés par rapport au rendement autorisé, ce qui est important au niveau du risque à court terme. Selon l'ACIG, l'experte a également admis qu'il y a un usage beaucoup plus important et répandu des comptes de frais reportés au Canada, pratique qui

25 Pièce A-35-1, pages 35 et 36.
26 Pièce B-1, GI-30, document 1, pages 10 à 14.
27 Pièce A-35-1, pages 179 et 180.

procure aux distributeurs canadiens une plus grande stabilité au niveau des rendements réalisés.

[108] Enfin, le D^r Booth souligne, dans sa présentation à l'audience intitulée « *US Data* », que Moody's considère que le risque réglementaire est, dans la majorité des cas, plus élevé pour les sociétés réglementées américaines que pour les sociétés réglementées canadiennes[28].

[109] Selon le D^r Booth, les pourcentages de capitaux propres dans la structure de capital des sociétés réglementées américaines sont plus élevés que ceux des sociétés réglementées canadiennes. Normalement, cette capitalisation plus élevée devrait les protéger contre un risque accru. Le D^r Booth montre, dans sa présentation[29] en audience, que la cote de crédit des sociétés réglementées américaines est de type BBB.

[110] L'ACIG conclut que la preuve dans le présent dossier n'apporte pas un éclairage nouveau suffisant pour permettre à la Régie d'en arriver à des conclusions différentes de celles auxquelles elle est parvenue dans la décision D-2009-156.

[111] La Régie juge que la preuve est peu concluante quant aux raisons qui justifieraient de retenir les taux accordés aux États-Unis comme base de référence pour établir un taux de rendement raisonnable au Québec. La preuve est, en effet, insuffisante quant aux données récentes sur les décisions américaines et quant à l'analyse des régimes réglementaire et institutionnel en vigueur chez nos voisins. Entre autres, le distributeur n'a pas fait la démonstration que les opportunités qui s'offrent sur le marché américain sont comparables, en termes de risque.

[112] De plus, la Régie juge que la preuve ne permet pas de conclure que les contextes réglementaire, institutionnel, économique et financier des deux pays et leurs impacts sur les opportunités qui en découlent pour les investisseurs sont comparables.

[28] Pièce C-2-26.
[29] Pièce C-2-26.

2.2.8 RÉSULTATS DE L’ANALYSE

[113] Le tableau suivant résume les valeurs retenues par la Régie pour chacun des paramètres.

Tableau 1

Paramètres	**Bas de la fourchette**	**Haut de la fourchette**
Taux sans risque	4,15 %	4,50 %
Prime de risque du marché avant la prise en compte des effets de la crise financière	5,50 %	5,75 %
Bêta brut d’un distributeur repère	0,50	0,55
Ajustement pour le risque de Gazifère	0,25 %	0,50 %
Frais d’émissions	0,50 %	0,50 %
Sous-total n^o 1 : Résultat produit par le MÉAF	**7,65 %**	**8,66 %**
Ajustement pour tenir compte des résultats des autres modèles	0,25 %	0,50 %
Sous-total n^o 2 : Taux de rendement sur l’avoir de l’actionnaire avant ajustement pour tenir compte des effets de la crise financière	**7,90 %**	**9,16 %**
Ajustement pour tenir compte des effets de la crise financière	0,25 %	0,55 %
Total : Taux de rendement sur l’avoir de l’actionnaire après ajustement pour tenir compte des effets de la crise financière	**8,15 %**	**9,71 %**

[114] Tenant compte de l’ensemble des conclusions précédentes, le taux de rendement sur l’avoir de l’actionnaire de Gazifère se situe dans une fourchette variant de 7,90 % à 9,16 %, avant ajustement pour les effets de la crise financière, et entre 8,15 % et 9,71 %, après ajustement pour les effets de la crise financière.

[115] **Sur la base de la preuve au dossier et pour l'ensemble des motifs exprimés précédemment, la Régie fixe le taux de rendement sur l'avoir de l'actionnaire de Gazifère à 9,10 % pour l'année tarifaire 2011. Ce taux inclut un ajustement de 30 points de base pour tenir compte des effets de la crise financière.**

2.3 FORMULE D'AJUSTEMENT AUTOMATIQUE

[116] À la suite d'une demande de la Régie, Gazifère dépose le calcul du taux de rendement sur l'avoir de l'actionnaire pour 2011 résultant de l'application de la formule d'ajustement actuelle. Ce taux de rendement s'établit à 8,46 %[30].

[117] Mme McShane recommande une nouvelle formule d'ajustement du taux de rendement pour tenir compte des écarts de crédit corporatif et d'une sensibilité moindre du coût de l'avoir propre aux variations des rendements des obligations du gouvernement.

[118] Mme McShane présente deux analyses au soutien de sa conclusion à l'effet que la sensibilité du coût de l'avoir propre aux variations des taux de rendement des obligations à long terme du gouvernement est plus petite que le facteur 0,75 de la présente formule. Ces analyses sont effectuées à partir de données américaines uniquement.

[119] Selon elle, même si les résultats de deux analyses produisent des estimateurs différents quant au facteur de sensibilité, il demeure que le coût de l'avoir propre est positivement relié aux variations observées entre les taux de rendement des obligations des sociétés et ceux des obligations du gouvernement.

[120] Dans la première analyse, Mme McShane fait une régression entre les taux de rendement trimestriels de 1995 à 2009, les rendements des obligations à long terme du gouvernement américain et l'écart entre les taux de rendement des obligations des sociétés de gestion américaines de cote A , dont une partie des actifs est réglementée, et les rendements des obligations à long terme du gouvernement américain.

[30] Pièce B-45, GI-30, document 5.

[121] Il en résulte que pour une augmentation (diminution) de 100 points de base des rendements des obligations à long terme du gouvernement américain, le coût de l'avoir de l'actionnaire augmente (diminue) de 47 points de base. Pour une augmentation (diminution) de 100 points de base de l'écart entre les taux de rendement des obligations des sociétés de gestion américaines de cote A et les rendements des obligations à long terme du gouvernement américain, le coût de l'avoir propre augmente (diminue) de 27 points de base.

[122] La deuxième analyse de Mme McShane teste, à partir du modèle AFM, la sensibilité du coût de l'avoir de l'actionnaire de 1995 à 2009 par rapport à, d'une part, la variation des rendements des obligations à long terme du gouvernement américain et, d'autre part, la variation de l'écart entre les taux de rendement des obligations des sociétés de gestion américaines de cote A et les rendements des obligations à long terme du gouvernement américain.

[123] Il en résulte que pour une augmentation (diminution) de 100 points de base des rendements des obligations à long terme du gouvernement américain, le coût de l'avoir propre augmente (diminue) de 65 points de base. Pour une augmentation (diminution) de 100 points de base de l'écart entre les taux de rendement des obligations des sociétés de gestion américaines de cote A et les rendements des obligations à long terme du gouvernement américain, le coût de l'avoir propre augmente (diminue) de 90 points de base.

[124] À partir de ces résultats, Mme McShane recommande la formule d'ajustement ci-dessous :

Le nouveau taux de rendement serait égal :

- au taux de rendement initial;
- plus 50 % de la variation du taux de rendement des obligations de 30 ans du gouvernement du Canada par rapport à celui fixé initialement;
- plus 50 % de la variation du taux de rendement des obligations à long terme de l'ensemble des sociétés canadiennes de cote A par rapport à celui fixé initialement. L'indice obligataire corporatif utilisé est le *DEX Long Term Index Corporate A.*

[125] Mme McShane produit un tableau montrant quel aurait été le taux de rendement sur l'avoir de l'actionnaire selon cette formule par rapport aux rendements autorisés de 1995 à 2011 par l'Office national de l'énergie (ONÉ)[31].

[126] L'experte McShane précise que le taux de rendement s'élève en moyenne à 10,6 %, soit un rendement comparable à la moyenne des taux autorisés aux États-Unis, qui est de 10,9 %. Elle conclut donc que cette formule est supérieure à celle que la Régie utilise présentement car elle produit des résultats comparables à ceux obtenus aux États-Unis.

[127] Enfin, Mme McShane propose que le taux de rendement et la formule soient révisés à tous les cinq ans, à moins que le taux de rendement autorisé par l'application de la nouvelle formule soit supérieur ou inférieur à 200 points de base du taux de rendement autorisé initialement.

[128] Le D[r] Booth est d'avis qu'il n'est pas nécessaire de changer la formule d'ajustement qui s'applique actuellement. Si la Régie décidait de changer cette formule, il propose, subsidiairement, une formule alternative qui tient compte des variations des rendements des obligations à long terme des sociétés réglementées de cote A.

[129] Subsidiairement, le D[r] Booth propose la formule d'ajustement ci-dessous :

Le nouveau taux de rendement serait égal :

- au taux de rendement initial;
- plus 75 % de la variation du taux de rendement des obligations de 30 ans du gouvernement du Canada par rapport à celui fixé initialement;
- plus 50 % de la variation du taux de rendement des obligations de 30 ans des sociétés réglementées canadiennes de cote A par rapport à celui fixé initialement (appelé ci-dessous écart de crédit). L'indice obligataire corporatif utilisé est l'indice C29530Y de Bloomberg.

[31] Pièce B-1, GI-4, document 1.2, schedule 28.

[130] Le D[r] Booth précise que le facteur de 0,50 pour tenir compte des écarts de crédit lui semble excessif. Il le conserve cependant, en précisant que sur la durée d'un cycle économique complet, l'effet est neutre. Selon un rapport de la Banque du Canada, le facteur d'ajustement dû aux changements des écarts de rendement des obligations corporatives relié au risque de défaut, qui peut être lié à un changement du coût de l'avoir propre, serait de l'ordre de 37 %[32].

[131] À partir de cette formule, le D[r] Booth refait le même exercice que Mme McShane, à savoir déterminer quel aurait été le taux de rendement sur l'avoir propre selon sa formule par rapport aux rendements autorisés de 1995 à 2011 par l'ONÉ.

[132] Selon le D[r] Booth, les taux de rendement produits par la formule de Mme McShane sont supérieurs aux taux de rendement autorisés de 1995 à 2011 par l'ONÉ. Selon lui, cela implique qu'aucun régulateur canadien n'aurait autorisé des rendements raisonnables sur cette période. Il ajoute également que, pendant cette période, les régulateurs canadiens ont refait l'exercice plus d'une fois, sur la base de preuves d'experts.

[133] Selon le D[r] Booth, la différence entre les taux de rendement produits par sa formule et les taux de rendement autorisés par l'ONÉ pour l'ensemble de la période de 1995 à 2011 est minime. Cependant, il y a des différences importantes pour certaines années, comme en 2009.

[134] Le D[r] Booth détermine quel aurait été le taux de rendement de Gazifère si la formule qu'il propose avait été employée. Il utilise le taux de rendement autorisé de Gazifère en 1999, qui était de 10 % avec un taux sans risque de 5,7 %. À partir des hypothèses que le taux sans risque est présentement de 4,5 % et que l'écart de crédit en 1999 était de 0,99 %, le rendement de Gazifère serait de 9,25 % selon sa formule. Le D[r] Booth considère qu'un écart de crédit normal serait de l'ordre de 94 points de base[33].

32 Pièce C-2-13, preuve du D[r] Booth, page 64.
33 Pièce C-2-13, preuve du D[r] Booth, page 64.

[135] Le Dr Booth considère cependant que les régulateurs n'ont pas besoin d'une formule qui capte les impacts de la pire crise financière depuis 1937, étant donné que la formule proposée génèrera une volatilité accrue des rendements autorisés annuels, et ce, pour peu de gain. Il est à noter également que l'ACIG est plutôt défavorable au deuxième ajustement de la formule proposée.

[136] Enfin, le Dr Booth note que si cette formule devait être retenue, la Régie ne devrait pas accorder un ajustement supplémentaire pour les effets de la crise financière.

[137] La Régie constate que la formule proposée par Mme McShane produit des rendements supérieurs à ceux autorisés par le passé. Quant à celle du Dr Booth, elle produit, sur un cycle économique, des rendements semblables à ceux octroyés, bien que, sur une base annuelle, ceux-ci divergent de ceux autorisés.

[138] La Régie est d'avis que la formule du Dr Booth permet de faire fluctuer le taux de rendement en fonction de la variation du taux de rendement des obligations de 30 ans des sociétés réglementées canadiennes, tout en gardant un rendement similaire à ceux autorisés sur une période d'un cycle économique. La Régie prend note que selon l'étude de la Banque du Canada, le facteur d'ajustement pour les écarts de crédit serait de l'ordre de 0,37.

[139] La Régie évalue que la formule alternative du Dr Booth aurait permis, malgré une volatilité accrue des rendements autorisés, d'obtenir des rendements autorisés mieux adaptés durant la crise financière. **La Régie conclut qu'il y a lieu de remplacer la formule actuelle par celle du Dr Booth aux fins d'établir le taux de rendement à compter de 2012.**

[140] La Régie est d'avis que les écarts de rendement des obligations des sociétés réglementées de cote A ne réagissent pas de la même façon que les écarts de rendement des obligations des sociétés non réglementées de cote A pendant les cycles économiques, et ce, particulièrement pendant une crise financière. **La Régie retient l'indice C29530Y de Bloomberg comme estimateur des écarts de crédit des sociétés réglementées canadiennes. Pour les prochains dossiers tarifaires, la Régie demande donc à Gazifère de fournir les données de Bloomberg du mois de septembre aux fins de l'application de la nouvelle formule.**

[141] En audience, le D[r] Booth a indiqué que l'indice de Bloomberg, lors du dépôt de sa preuve, était de 1,3 % alors qu'au moment de l'audience, il était d'environ 1,5 %[34]. **La Régie retient la valeur de 1,5 % de l'indice Bloomberg aux fins d'application de la nouvelle formule.** Sur la base d'un écart de crédit normal estimé à environ 90 points de base, l'ajustement pour les écarts de crédit ajoute, avec la nouvelle formule, 30 points de base au taux de rendement.

[142] La Régie retient pour l'année tarifaire 2011 un ajustement de 30 points de base pour l'effet de la crise financière. **La Régie estime que, pour 2012 et les années subséquentes, cet ajustement est pris en compte par le deuxième membre de la nouvelle formule d'ajustement automatique.** Ainsi, dans l'éventualité où les écarts de crédit demeurent élevés, l'ajustement sera maintenu. À l'inverse, si les écarts de crédit reviennent à leur normale, l'ajustement sera enlevé.

[143] **La Régie fixe également, aux fins de l'application de la nouvelle formule, le taux sans risque à 4,25 %.**

[144] Ainsi, le taux de rendement sur l'avoir de l'actionnaire pour l'année 2012 et les années subséquentes sera calculé selon la formule présentée à l'annexe 1.

[145] La Régie précise que le taux de rendement sur l'avoir de l'actionnaire résultant de l'application de cette formule devra être exprimé en pourcentage arrondi à deux décimales.

2.4 COÛT DE LA DETTE

[146] Gazifère explique en audience que le financement se fait exclusivement auprès d'Enbridge Inc. (Enbridge), sa société mère. La dette à court terme de Gazifère est une proportion de la marge de crédit consolidée dans Enbridge.

[147] Le taux de la dette à court terme utilisé par Gazifère correspond au taux d'escompte établi par le service « *Economic & Market Analysis* » d'Enbridge Gas Distribution Inc. (EGD).

[34] Pièce A-35-2, pages 141 et 142.

[148] Gazifère dépose la méthodologie et les données utilisées pour établir ce taux d'escompte[35]. Selon cette méthodologie, la moyenne des prévisions de taux directeur de six institutions financières est ajustée pour obtenir un taux raisonnable. Une prime de 2 %, représentant l'écart entre le taux directeur et le taux préférentiel de la Banque du Canada depuis décembre 2008, est ajoutée à cette prévision.

[149] Le taux en résultant passe de 2,21 % en 2010 à 3,90 % en 2011[36].

[150] La Régie constate que les fluctuations de ce taux sont importantes. Elle constate aussi que la méthodologie utilise certains paramètres peu documentés, comme l'ajustement à la moyenne des taux ainsi que la période utilisée pour établir l'écart de 2 %.

[151] **La Régie demande à Gazifère de déposer, pour examen dans le prochain dossier tarifaire, la méthodologie et les données utilisées pour établir le taux d'escompte, en incluant minimalement les données présentées à la pièce B-43, GI-41, document 1.1.**

[152] Par ailleurs, les émissions de la dette à long terme de Gazifère sont financées par Enbridge au taux des obligations de 10 ans du gouvernement du Canada plus une prime de risque pour tenir compte de la cote de crédit de Gazifère selon le concept d'isolement.

[153] Gazifère dépose la méthodologie d'établissement du coût de la dette à long terme[37]. L'établissement de la cote de crédit et de la prime de risque repose sur une évaluation de *RBC Capital Markets*. Étant donné sa taille, la cote de crédit de Gazifère est évaluée comme un « BBB bas ».

[154] En audience, Gazifère indique qu'au cours des dernières années, il n'y a pas eu de modification à la méthodologie retenue pour établir son financement. Elle dépose les primes de risque annuelles qui ont été utilisées pour établir le coût de sa dette depuis 2002[38]. À partir de ce document, il peut être constaté que les primes de risque sont volatiles.

35 Pièce B-43, GI-41, document 1.1.
36 Pièce B-41, GI-35, document 2.2, page 2.
37 Pièce B-11, GI-31, document 1.3 et pièce B-38, GI-30, document 4.1.
38 Pièce B-38, GI-30, document 3.

[155] Gazifère souligne qu'elle et Enbridge, en plus d'être deux sociétés distinctes, sont régies par deux organismes de réglementation distincts et sont assujetties à toute une panoplie de législations distinctes.

[156] Gazifère rappelle que la méthodologie pour établir le coût de sa dette a été approuvée par la Régie dans la décision D-2006-158[39]. Selon Gazifère, le principe du concept d'isolement a été reconnu dans cette décision et c'est exactement de cette façon qu'elle a établi le coût de la dette dans le présent dossier.

[157] Enfin, Mme McShane indique que si Gazifère émettait ses propres titres de dette, le coût de financement serait plus élevé et les conditions seraient plus contraignantes. Elle conclut que les clients de Gazifère doivent payer le coût de la dette comme si elle se finançait seule. En d'autres mots, il faut appliquer le concept d'isolement.

[158] Selon le Dr Booth, s'il n'y avait pas de frontière provinciale, les actifs de Gazifère ne seraient pas différents de ceux d'Enbridge et seraient intégrés à ces derniers. Sur cette base et considérant le principe économique que des actifs semblables devraient générer des rendements équivalents, il indique que Gazifère devrait avoir la même structure de capital, le même coût de la dette et le même taux de rendement qu'Enbridge.

[159] Il indique également que le coût de financement d'Enbridge est supérieur à celui d'EGD étant donné que c'est une société de gestion. Typiquement, une société de gestion a un coût de financement d'environ 25 points de base supérieur à la filiale d'exploitation. De plus, durant la crise financière, ce coût a augmenté étant donné que les sociétés de gestion comptent sur les dividendes de la filiale d'exploitation pour faire les paiements d'intérêts sur leur dette.

[160] Selon le Dr Booth, durant la crise financière, l'écart de financement entre celui d'Enbridge et celui d'EGD a augmenté significativement.

[161] Selon le Dr Booth, la réglementation des sociétés de services publics vise à limiter le pouvoir d'un monopole de fixer des prix élevés tout en rendant accessibles aux consommateurs les bénéfices normalement associés à la concurrence. Sur cette base, il indique qu'on ne devrait pas surprotéger les sociétés de services publics et ainsi empêcher les consommateurs de bénéficier des économies d'échelles que le statut de monopole

[39] Dossier R-3587-2005.

permet d’atteindre. Il donne l’exemple de la Commission de l’énergie de l’Ontario (CÉO) et des distributeurs d’électricité qu’elle réglemente pour appliquer ces principes.

[162] Le D[r] Booth précise qu’il ne faut pas établir le coût du capital selon le concept d’isolement mais plutôt établir ce coût sur une base de marché concurrentiel et ainsi laisser les forces du marché l’emporter.

[163] Il recommande que le coût de la dette soit le même que celui d’EGD, que le rendement sur l’avoir propre soit similaire à celui d’EGD et que la structure de capital soit laissée à 40 % de capitaux propres et à 60 % de capitaux empruntés.

[164] La Régie constate que les deux experts ont des points de vue nettement différents.

[165] La Régie a depuis longtemps établi le coût de la dette de Gazifère sur la base du principe d’isolement. La Régie juge que la preuve ne permet pas de modifier cette approche. **Néanmoins, considérant l’ampleur des écarts de crédit et leur volatilité, particulièrement pendant la crise financière, la Régie demande à Gazifère, pour le prochain dossier tarifaire, de déposer les documents suivants :**

- **la méthodologie et les modifications, le cas échéant, avec les explications, telles que présentées à la pièce B-11, GI-31, document 1.3;**
- **le rapport externe d’évaluation de la cote de crédit de Gazifère, tel que présenté à la pièce B-38, GI-30, document 4.1;**
- **les écarts de crédit d’Enbridge et d’EGD par rapport aux obligations du gouvernement du Canada, avec les dates des financements, le terme et le coupon, tels que présentés à la pièce B-11, GI-30, document 1.18, page 1.**

2.5 CONCLUSION

[166] La Régie doit, par sa loi constitutive, permettre un rendement raisonnable sur la base de tarification du distributeur. Dans le cadre de cet exercice, et tel que mentionné précédemment, la méthode que la Régie utilise relève de sa discrétion. À cet effet, l'arrêt Hope précise que c'est la résultante de l'exercice réglementaire qui doit rencontrer la norme de rendement raisonnable et non pas la méthode pour s'y rendre[40].

[167] La Régie retient, comme base première de référence, les résultats produits par le MÉAF. La Régie tient compte, de plus, des résultats des autres modèles aux fins de son appréciation du taux de rendement à octroyer à Gazifère.

[168] **La structure de capital n'ayant fait l'objet d'aucun débat, la Régie maintient la présente structure de capital composée de 40 % de capitaux propres et de 60 % de capitaux empruntés.**

[169] **Sur la base de la preuve au dossier et pour l'ensemble des motifs exprimés précédemment, la Régie fixe le taux de rendement sur l'avoir de l'actionnaire de Gazifère à 9,10 % pour l'année tarifaire 2011. Ce taux inclut un ajustement de 30 points de base pour tenir compte des effets de la crise financière. À partir de 2012, cet ajustement évoluera en fonction du deuxième membre de la nouvelle formule d'ajustement automatique qui sera, dès lors, en application.**

[170] **Sur la base d'un taux sans risque de 4,25 %, le taux de rendement autorisé de 9,10 % correspond à une prime de risque implicite de 4,85 % pour le distributeur.**

[171] **La Régie demande à Gazifère de mettre à jour, au plus tard le 10 décembre 2010 à 12 h, le taux de rendement de la base de tarification et le coût en capital prospectif. La Régie demande également à Gazifère de déposer, dans les futurs dossiers tarifaires, le calcul détaillé du coût en capital prospectif, tel que déposé dans le présent dossier[41].**

[40] *Federal Power Commission* c. *Hope Natural Gas Company* 320 U.S. 591 (1944).
[41] Pièce B-11, GI-30, document 1, pages 18 et 19.

2.6 OPINION DU RÉGISSEUR RICHARD CARRIER EN CE QUI A TRAIT AU TAUX DE RENDEMENT

[172] Je présente, ci-après, les motifs qui sous-tendent ma conclusion quant au taux de rendement sur l'avoir de l'actionnaire à accorder à Gazifère pour l'année 2011. Bien qu'à plusieurs égards je retiens une conclusion similaire à celle de mes collègues, les motifs exprimés contiennent parfois des nuances, parfois des conclusions qui les distinguent. Ils forment donc un tout et doivent être lus comme tels. Enfin, je fais mien l'ensemble du résumé de la preuve, tel que présenté dans la décision majoritaire.

Taux sans risque

[173] Aux fins de la fixation d'un taux de rendement raisonnable pour l'année 2011, je retiens, dans le cadre de mon appréciation, un taux de 4,25 % comme point de référence pour les calculs afférents au MÉAF.

Prime de risque du marché selon les données historiques

[174] Il est utile, voire essentiel, de déterminer, dans un premier temps, les données de référence utilisées quant aux rendements sur l'équité observés sur les marchés et le contexte économique et financier dans lequel ces rendements ont été réalisés.

[175] Aux fins de mon appréciation des données historiques, je retiens la même approche que celle utilisée par la Régie dans ses décisions antérieures, soit le recours à des moyennes arithmétiques de longue période.

[176] Les données soumises en preuve par les deux experts permettent de situer la moyenne des rendements sur l'équité réalisés à 11,6 % au Canada et à 11,8 % aux États-Unis[42]. Les rendements moyens observés sur les obligations gouvernementales d'un terme de 30 ans ont été, pour leur part, de 6,4 % au Canada et de 5,7 % aux États-Unis. Il est à noter, par ailleurs, que les rendements réalisés l'ont été dans un contexte où l'inflation moyenne sur l'ensemble de la période était de 3,1 %.

[42] Preuve de Mme McShane, pièce B-1, GI-4, document 1, Schedule 6, page 2; preuve du Dr Booth, pièce C-2-13, Appendix B, Schedule 1 et Schedule 10.

Tableau 2

Données historiques sur les marchés	**Can** (1924-2009)	**US** (1926-2009)
Rendements sur l'équité (%)	**11,60**	**11,80**
Rendements des obligations de long terme (%)	**6,40**	**5,70**
Prime de risque du marché (%)	**5,20**	**6,10**
Inflation (%)	**3,10**	**3,10**

[177] Les données retenues sont représentatives des périodes de référence utilisées. D'autres résultats peuvent être obtenus en retenant d'autres périodes de référence ou en utilisant d'autres types de moyennes.

[178] Ces données sont utiles tant pour l'établissement de la prime de risque du marché dans le cadre du MÉAF que pour l'appréciation générale du caractère raisonnable des taux de rendement alloués aux entreprises réglementées. Ce sont des données objectives, établies à partir de statistiques fiables pour l'ensemble des secteurs de l'économie, lesquels, pour la plupart, sont en situation de concurrence sur les marchés. En ce sens, ces données historiques constituent un point de repère important pour évaluer le rendement attendu par les investisseurs dans le marché.

[179] L'établissement de la prime de risque du marché dans le cadre du MÉAF traditionnel repose sur l'estimation des rendements moyens observés sur des périodes suffisamment longues pour atténuer les effets reliés aux particularités des différents cycles économiques. Les périodes retenues ci-haut respectent ce critère.

[180] Tant Mme McShane que le D^r Booth mentionnent que la prime de risque du marché historique au Canada a été influencée artificiellement à la baisse par le niveau relativement élevé des taux obligataires canadiens pendant les années 80 et 90, lequel découlait du contexte budgétaire difficile du gouvernement canadien à l'époque. Ce phénomène n'a plus la même ampleur aujourd'hui. Aux fins de mon appréciation, je retiens, comme plage inférieure, une valeur de 5,5 % comme prime de risque du marché, calculée à partir des données historiques canadiennes.

[181] Comme plage supérieure de la prime de risque du marché basée sur des données historiques, je retiens, comme mes collègues, une valeur de 5,75 % basée sur les données historiques au Canada et aux États-Unis, bien qu'il soit également plausible de retenir une valeur de 6,0 % calculée uniquement à partir des données historiques américaines. Une telle valeur peut se justifier par le degré élevé d'intégration des économies canadienne et américaine et la très grande mobilité des capitaux.

[182] Aux fins de mon appréciation, je retiens la valeur supérieure de la fourchette établie. J'aborderai, dans une autre section, l'enjeu relatif à l'utilisation des seules données historiques comme estimateur du rendement attendu aujourd'hui et dans le futur par les investisseurs.

Bêta brut (risque d'un distributeur repère)

[183] Dans le cadre de l'application du MÉAF traditionnel, le risque d'un titre est évalué sur un plan statistique, en comparant l'écart type des rendements mensuels observés sur le marché pour une entreprise ou un secteur donné avec celui du marché en général. Ce paramètre, appelé bêta brut, est ensuite utilisé pour établir, à l'étape suivante, la prime de risque de ce secteur, en comparaison de celle du marché en général.

[184] Sur la base de la preuve, je juge approprié de retenir, dans le cadre de l'application de la formulation traditionnelle du MÉAF, la notion de bêta brut. Elle constitue une base relativement objective aux fins du calcul de la prime de risque. Selon la preuve au dossier, cette valeur peut être située dans une plage de 0,50 à 0,55.

[185] En ce qui a trait à l'utilisation de bêtas ajustés, je retiens la conclusion exprimée par la Régie dans ses décisions antérieures à l'effet que l'explication couramment utilisée dans les milieux de la recherche financière pour justifier un ajustement des bêtas bruts, soit la tendance observée sur le plan empirique pour les bêtas en général d'évoluer à terme vers la moyenne du marché qui est de un (1), ne peut être valablement retenue dans le cas d'une entreprise réglementée. En présence de droits exclusifs de distribution, il apparaît difficile de concevoir comment le risque propre à cette activité pourrait se modifier substantiellement à la hausse et évoluer vers le risque du marché au fil des ans.

[186] Ceci ne résout toutefois pas nécessairement de façon entière la problématique reliée à la qualité des bêtas bruts et à leur capacité à prédire correctement les rendements

réalisés dans le cadre de l'application du MÉAF. Il s'agit d'une question qui continue de susciter des débats entre experts.

Prime de risque d'un distributeur repère

[187] Sur la base des paramètres précédents, la prime de risque d'un distributeur repère peut être située dans une fourchette de 2,75 % à 3,16 %.

Frais d'émission

[188] Aux fins de mon appréciation, je juge approprié de retenir un coussin pour les coûts directs d'émission et escomptes non autrement compensés dans le calcul du revenu requis de l'entreprise réglementée. Ces coûts spécifiques seraient de l'ordre de 30 à 35 points de base selon l'examen détaillé effectué dans le dossier R-3690-2009.

[189] En ce qui a trait à une compensation pour les effets de dilution, à moins de preuve prépondérante à l'effet contraire, cet ajustement n'apparait pas nécessaire pour une entreprise réglementée. Sous l'hypothèse d'une structure de capital constante au fil des ans, et toutes autres choses étant égales par ailleurs, toute hausse du besoin total de financement par voie d'équité et de dette découle d'une hausse équivalente de la valeur de la base de tarification engagée aux fins de l'activité réglementée. Or, en pareil cas, le rendement total sur l'équité augmentera dans la même proportion que le rendement sur la base de tarification, ce qui devrait neutraliser entièrement, pour un investisseur le moindrement averti, toute crainte de dilution indue et ainsi maintenir la valeur des titres au marché intacte. Tel n'est pas nécessairement le cas pour les entreprises en situation de concurrence sur le marché qui peuvent émettre des titres à diverses fins autres que de financer des projets de croissance.

[190] La proposition de Mme McShane de prévoir une compensation suffisante afin de maintenir la valeur au marché des titres n'est pas retenue. Cette question s'apparente à celle discutée dans la décision D-2009-156[43], aux pages 54 à 58. Dans cette décision, la Régie n'a pas retenu la proposition d'établir le rendement de l'actionnaire sur la base d'une structure de capital reflétant les valeurs au marché plutôt que les valeurs aux livres.

[43] Dossier R-3690-2009.

[191] Compte tenu de ce qui précède et de la preuve au dossier, je retiendrais, à titre de frais reliés aux émissions, une fourchette variant entre 30 et 50 points de base.

Rendement d'un distributeur repère selon le MÉAF établi à partir de données historiques

[192] Les données précédentes permettent d'établir un second point de référence utile dans l'appréciation du rendement à octroyer. Sur la base de l'application du MÉAF dans sa formulation traditionnelle et à partir de données historiques seulement, le taux de rendement d'un distributeur repère se situerait dans une fourchette de 7,30 % à 7,91 %.

[193] Un tel résultat doit toutefois être apprécié à la lumière du contexte économique et financier d'aujourd'hui. Les deux experts abordent les enjeux y reliés dans leur preuve respective. Les sections qui suivent portent sur ces questions.

Ajustement - Prime de risque du distributeur repère (MEAF) et taux sans risque courant

[194] Au présent dossier, Mme McShane soumet que le modèle « Prime de risque », tout comme les autres modèles utilisés pour établir un rendement raisonnable, sert d'abord et avant tout à déterminer le rendement attendu par les investisseurs aujourd'hui et dans le futur. En conséquence, selon elle, les données historiques sur la prime de risque pour les périodes passées doivent être appréciées en fonction de cet objectif et être ajustées au besoin lorsqu'elles ne sont pas suffisamment représentatives des conditions économiques et financières contemporaines et à venir.

[195] Elle soumet, entre autres, à l'appui de sa position que, pour la période d'après-guerre et sur la base des moyennes mobiles sur dix ans des périodes passées, il n'y a pas eu de tendance notable à la hausse ou à la baisse des rendements totaux sur l'équité observés entre 1947 et 2009, le rendement moyen pour la période se situant dans une plage de 11,5 % à 12,0 %. Elle juge donc cet estimé valable pour déterminer le rendement total du marché attendu aujourd'hui par les investisseurs. Comme la prévision 2011 du taux des obligations de 30 ans du gouvernement canadien est d'environ 4,7 % et la prévision à moyen et à long terme est de 5,25 %, elle en déduit une prime de risque du marché attendue par les investisseurs de l'ordre de 6,75 % alors que la moyenne historique de longue période pour le marché américain est de l'ordre de 6,1 %.

[196] Le Dr Booth soumet que la prime de risque se situe entre 5,0 % et 6,0 %, et ce, sur la base de l'ensemble de ses analyses, y incluant, à leur appui, l'examen des résultats du sondage du professeur Fernandez portant sur les approches généralement utilisées par les professeurs de finance, les analystes financiers et les dirigeants de sociétés.

[197] Comme mentionné par la Régie dans la décision D-2007-116[44], l'application du MÉAF soulève des difficultés particulières lorsque la fixation du taux de rendement intervient dans une période où les taux courants des obligations gouvernementales s'écartent de façon significative du taux moyen de longue période. La Régie s'exprimait de la façon suivante :

> « *Selon la Régie, l'application du modèle MÉAF présente une difficulté additionnelle lorsque l'évaluation du rendement intervient dans une période où les taux courants des obligations gouvernementales s'écartent de façon significative du taux moyen de longue période. La prime de risque étant calculée sur de longues périodes et représentant la différence entre la moyenne arithmétique des rendements du marché et de ceux des obligations gouvernementales, cette prime est donc fondamentalement représentative des conditions qui prévalaient sur cette même période. Un ajustement s'impose donc dans l'appréciation par la Régie lorsque les conditions du marché obligataire s'éloignent de cette moyenne.*
>
> [...]
>
> *La Régie considère qu'il s'agit d'un premier débat sur cette question qui mérite plus ample examen. Toutefois, ce débat ne saurait changer substantiellement le taux de rendement raisonnable auquel a droit l'actionnaire.*
>
> [...]
>
> ***Dans le présent dossier, la Régie apporte un ajustement à la hausse de 40 points de base des résultats produits par le MÉAF.*** »

[198] Dans la décision D-2009-156, la Régie apportait à nouveau un ajustement de même nature aux résultats produits par le MÉAF.

[199] La situation au présent dossier s'apparente à celle examinée dans ces dossiers et elle est même exacerbée par le fait que le taux sans risque est maintenant de l'ordre de 4,25 % alors qu'il se situait à 4,78 % en 2007. Il s'agit d'une situation relativement

[44] Dossier R-3630-2007, page 28.

nouvelle dans l'histoire récente, notamment depuis les années 2005-2006 alors que le taux sans risque est passé sous la barre des 5,0 %.

[200] La problématique en cause tire son origine du fait que, dans le cadre de l'application usuelle du MÉAF, la prime de risque d'un titre est ajoutée au rendement courant des obligations de long terme des gouvernements pour établir le rendement attendu par les investisseurs. La prémisse sous-jacente à ce modèle serait qu'il est raisonnable de supposer que les attentes des investisseurs et les rendements sur les marchés varient en parallèle avec l'évolution des taux des obligations gouvernementales ou taux sans risque. Cette prémisse serait toutefois discutable si les taux de rendement observés sur les marchés présentent plutôt une certaine stabilité ou constance dans le temps.

[201] Force est de constater que les deux experts ne partagent pas tout à fait le même point de vue quant à la stabilité des taux de rendement sur l'équité dans le temps. Mme McShane considère que les rendements nominaux sur l'équité sont stables dans le temps et, qu'en conséquence, la prime de risque attendue devrait être calculée en tenant compte de cette réalité et être établie en soustrayant de ces rendements observés les taux courants ou attendus des obligations gouvernementales. Selon la preuve du Dr Booth, ce seraient plutôt les rendements réels sur l'équité qui seraient constants et non les rendements en termes nominaux[45].

[202] L'analyse des données empiriques de Mme McShane, bien qu'utile, n'apparaît pas suffisamment documentée et robuste pour être utilisée directement.

[203] Par ailleurs, l'hypothèse d'une certaine stabilité des rendements dans le temps semble logique sur le plan conceptuel, l'investisseur recherchant, dans une perspective de moyen et de long terme, un rendement stable dans le temps, après prise en compte de l'inflation.

[204] Selon les données en preuve, l'écart entre les taux d'inflation historiques de 3,1 % et la projection pour le futur, qui est généralement de l'ordre de 2,0 %, est d'environ 100 points de base. Cette baisse est toutefois moins prononcée que la baisse observée d'environ 200 points de base du rendement des obligations gouvernementales, laquelle sert de référence pour l'application du MÉAF. Un tel résultat militerait en faveur d'un

[45] Pièce C-2-13, Appendix B, page 7.

ajustement de la prime de risque implicite si le rendement réel attendu par les investisseurs est stable dans le temps.

[205] La preuve au dossier ne permet pas de tirer des conclusions définitives relativement à cette problématique. Il s'agit d'une question d'ordre empirique qui pourrait faire l'objet d'un examen plus détaillé dans le futur.

[206] Par ailleurs, les deux experts reconnaissent que, pour la mise à jour du taux de rendement que la Régie autorisera au présent dossier, il est adéquat d'utiliser, pour les années futures, une formule d'ajustement de la prime de risque implicite lorsque les taux des obligations de long terme, ou taux sans risque, fluctueront à la hausse ou à la baisse. La divergence d'opinions à cet égard, si divergence il y a, porte surtout sur le niveau de cet ajustement, soit de 25 ou 50 points de base par 100 points de variation des taux obligataires de référence, plutôt que sur son fondement. Les deux experts reconnaissent ainsi, de ce point de vue, que la prime de risque implicite du distributeur varie effectivement en fonction du niveau des taux obligataires.

[207] Sur la base de la preuve au présent dossier et en tenant compte des décisions antérieures de la Régie, un ajustement de la prime de risque implicite d'un distributeur apparaît approprié lorsque les taux courants des obligations gouvernementales s'éloignent de façon notable de la moyenne historique utilisée pour le calcul de la prime de risque.

[208] Sur un plan pratique, la valeur de l'ajustement à retenir pour le taux de rendement de l'année 2011 peut être approximée, au présent dossier, en fonction d'un facteur d'élasticité représentant 25 % de l'écart entre le taux sans risque de longue période et le taux sans risque courant, soit le même facteur d'ajustement que celui de la formule d'ajustement automatique existante. L'ajustement retenu serait donc de l'ordre de 40 ou de 50 points de base selon que l'on réfère à l'écart entre, d'une part, la moyenne historique des taux sans risque au Canada ou aux États-Unis et, d'autre part, le taux sans risque courant de 4,25 %.

Les écarts de crédit courants

[209] Dans le cadre de son analyse quant à l'établissement d'un taux de rendement raisonnable, le Dr Booth recommande un ajustement de 50 points de base pour tenir compte du fait que les effets de la crise financière sont encore présents. Il note la persistance d'un degré élevé de nervosité sur les marchés financiers. Il mentionne

également que les écarts de crédit se sont amplifiés entre le moment du dépôt de sa preuve et l'audience.

[210] Mme McShane est d'avis que, pour l'essentiel, la crise financière est derrière nous. Cependant, elle mentionne que la problématique fondamentale de la formule d'ajustement et les résultats qu'elle a produits par le passé au Canada n'étaient pas reliés à la crise financière. Cette problématique était préexistante et n'a été qu'exacerbée par la crise. Selon elle, la problématique demeure donc entière. Ses recommandations quant au taux de rendement sur l'avoir de l'actionnaire et à la formule d'ajustement tiennent compte de cette constatation.

[211] La question des écarts de crédit et son lien avec l'établissement d'un taux de rendement raisonnable sur l'avoir de l'actionnaire ont fait l'objet de débats répétés devant la Régie depuis 2007. La Régie notait l'insuffisance de la preuve à cet égard dans sa décision D-2008-140[46]. Par ailleurs, dans sa décision D-2009-156, la Régie retenait, à titre d'ajustement pour compenser les effets de la crise, un ajustement de la prime de risque et du taux de rendement applicable au distributeur se situant dans une plage variant entre 0,25 % et 0,55 %.

[212] Au présent dossier, il peut être constaté que les écarts de crédit sont encore à un niveau supérieur à leur moyenne historique. Les soubresauts observés sur les marchés financiers en 2009, en lien avec la problématique des déficits budgétaires et des dettes souveraines en Europe, illustrent également la relative fragilité des marchés au sortir de la pire crise financière depuis les années 1930.

[213] Selon la preuve au dossier, les écarts de crédit demeurent élevés. Il est plausible qu'ils persistent et qu'ils demeurent volatils pour une durée relativement longue.

[214] Tous les experts s'entendent pour dire que le rendement sur l'avoir propre devrait, dans des circonstances normales, être plus élevé que le rendement sur les titres obligataires, en raison du risque plus élevé que les actionnaires assument par rapport aux détenteurs d'obligations corporatives. Il est aussi généralement admis que les écarts de crédit peuvent fluctuer au cours des différentes phases d'un cycle économique.

[46] Dossier R-3662-2008 Phase 2.

[215] Sur la base de la preuve au dossier, un ajustement de la prime de risque établie dans le cadre du MÉAF apparaît justifié.

[216] À cet égard, il y a lieu de prendre en compte le niveau des écarts de crédit observé au moment de l'audience, soit d'environ 1,50 % selon l'indice Bloomberg, représentant les écarts entre le rendement des obligations de long terme des sociétés réglementées et celui des obligations gouvernementales de même durée. Par rapport à la moyenne historique de 0,90 % pour ce même indice selon la preuve du D^{r} Booth, l'écart serait de l'ordre de 60 points de base.

[217] En ce qui a trait au quantum de l'ajustement à retenir, la partie inférieure de cette plage peut être établie sur la base du facteur d'élasticité proposé par les experts pour cette même variable dans le cadre de la discussion sur les formules d'ajustement à retenir dans le futur, soit 50 % de l'écart observé ou 30 points de base. La partie supérieure de cette plage peut être fixée à 100 % de l'écart, soit 60 points de base.

[218] Sur la base de la preuve au présent dossier, notamment quant au contexte financier, je retiens, aux fins de mon appréciation, un ajustement de l'ordre de 40 à 50 points de base.

Distributeur repère selon le MÉAF ajusté

[219] Sur la base de ce qui précède, le taux de rendement d'un distributeur repère selon l'approche d'un MÉAF ajusté peut s'établir dans une fourchette variant entre 8,0 % et 9,01 %.

Les autres modèles et autres considérations

[220] Mme McShane présente les résultats découlant de l'utilisation de divers autres modèles ou variantes de ces modèles. Certaines difficultés surgissent aux fins de l'interprétation de ceux-ci.

[221] Ces difficultés portent, notamment, sur les effets reliés au phénomène de circularité, soit le fait de se baser directement ou indirectement sur les résultats des entreprises réglementées ou sur les valeurs au marché pour établir le rendement attendu

par les investisseurs, alors que ces mêmes résultats dépendent de façon plus ou moins étroite des décisions passées des régulateurs.

[222] Ces difficultés portent également sur la qualité de l'échantillon retenu, notamment quant au degré de risque supporté par les entreprises américaines composant l'échantillon comparativement au risque moyen d'un distributeur repère au Canada.

[223] Mme McShane conclut à l'inexistence d'un tel écart. Elle soutient que les environnements réglementaires, économiques et financiers au Canada et aux États-Unis sont sensiblement les mêmes.

[224] Le Dr Booth soutient que le différentiel de risque peut justifier un écart de 90 à 100 points de base pour un distributeur réglementé aux États-Unis. Il s'appuie, entre autres, sur les résultats de l'analyse de Moody's d'août 2009, laquelle mentionne le caractère généralement plus prévisible et plus favorable à l'environnement réglementaire au Canada.

[225] La preuve du Dr Booth concernant l'analyse de Moody's est utile puisqu'il s'agit de l'analyse d'une tierce partie spécialisée dans la notation des titres des sociétés réglementées. Une preuve et un examen encore plus poussé des paramètres considérés par ces agences de notation apparaissent être une piste utile à explorer pour le futur.

[226] Au-delà des remarques souvent générales soumises par les experts, l'importance de cet enjeu aux fins de la détermination d'un rendement raisonnable pour l'investisseur justifie que des efforts plus grands soient déployés pour comparer les risques encourus par les entreprises réglementées au Canada et aux États-Unis, mais idéalement aussi par rapport aux autres secteurs d'activité économique où les entreprises sont soumises à la concurrence en retenant, par exemple, un secteur d'activité dont le facteur bêta serait égal à celui du marché.

[227] À cette fin, il serait utile de pousser l'analyse des régimes réglementaires, par exemple, en comparant le traitement applicable aux risques reliés aux contrats d'approvisionnement et de transport, les règles applicables aux erreurs de prévision, les règles en matière d'autorisation des projets d'investissement selon que les autorisations sont données a priori ou a posteriori, les règles applicables pour l'acquisition et la disposition des actifs excédentaires ou devenus désuets, et ce, au vu de la jurisprudence applicable.

Prime de risque d’un distributeur repère selon l’historique de rendement des sociétés réglementées

[228] Dans le cadre de cette approche, Mme McShane obtient une prime de risque historique de 11,0 % pour les sociétés réglementées aux États-Unis (1947-2009) et au Canada (1956-2009). Cette méthode a l’avantage d’être simple d’application. Elle soulève cependant plusieurs difficultés dans l’interprétation des résultats.

[229] Les données canadiennes reflètent une période au cours de laquelle les taux obligataires de long terme étaient très élevés. Dans la mesure où les rendements autorisés tenaient compte de cette réalité, les résultats obtenus à l’aide de cette approche portent sur une période possiblement peu représentative du contexte économique actuel.

[230] Quant aux données américaines, le phénomène de la représentativité de l’échantillon en termes de risque et l’impact relié au choix de la période de référence doivent être pris en considération.

Prime de risque d’un distributeur repère selon l’approche d’actualisation des flux monétaires (AFM) des entreprises réglementées

[231] Mme McShane obtient une prime de risque de 9,4 % à l’aide de ce modèle avant frais d’émission comparativement à 9,25 % avec son estimation du MÉAF. Les particularités propres au modèle AFM sont abordées aux paragraphes qui suivent.

Rendement d’un distributeur repère selon le modèle d’actualisation des flux monétaires (AFM)

[232] Mme McShane présente diverses variantes de ce modèle. Elle mentionne qu’il s’agit d’une alternative au MÉAF largement utilisée et que ce modèle est le principal modèle utilisé par les régulateurs aux États-Unis.

[233] Le modèle repose sur l’estimation des flux monétaires futurs qui seront constitués des dividendes versés par l’entreprise et l’actualisation de l’ensemble de ces flux en dollars d’aujourd’hui. À l’aide de ce modèle, Mme McShane estime le rendement d’un distributeur repère, avant frais d’émission, à 10,0 %.

[234] La spécification des paramètres du modèle AFM est particulièrement importante. Dans sa formulation de base, ce modèle exige que soient estimés les flux des dividendes de la société évaluée ou de l'échantillon pour chacune des années dans le futur et d'actualiser ces flux en dollars d'aujourd'hui. Les difficultés reliées à une estimation correcte de la croissance des dividendes par action « g » ne sont pas négligeables. Un changement mineur de cette variable peut causer un impact important du fait que, dans le cadre de ce modèle, l'actualisation des données porte sur l'ensemble des périodes futures, théoriquement jusqu'à l'infini.

[235] Mme McShane utilise, dans un premier temps, les projections des analystes financiers pour établir la valeur du paramètre « g ». Elle utilise également ses propres estimations d'un taux de croissance soutenable à long terme. Le D^r Booth conteste les diverses hypothèses de Mme McShane. Il soumet, entre autres, que l'utilisation des prévisions des analystes financiers fait l'objet d'une grande controverse en raison du caractère trop optimiste de leurs prévisions, tel qu'il a pu être observé de temps à autre dans le passé.

[236] Bien qu'étant en désaccord avec cette hypothèse, Mme McShane soumet que dans la mesure où les investisseurs croient ces prévisions et les intègrent dans leurs décisions, les résultats du modèle AFM constituent un estimé non biaisé des attentes des investisseurs[47]. Une telle conclusion apparaît discutable. Dans le marché privé non réglementé, l'investisseur sera sanctionné par le marché si ses décisions sont basées sur des prévisions d'analystes qui s'avèreraient, en moyenne, trop optimistes. À l'inverse, si les régulateurs devaient baser leurs décisions sur les mêmes prévisions en moyenne trop optimistes des analystes, ce biais serait alors introduit dans les tarifs sans sanction possible par le marché. En pareil cas, un rendement biaisé à la hausse serait réalisé par l'actionnaire au détriment des usagers qui devraient acquitter une facture plus élevée que nécessaire.

[237] Aux fins de l'utilisation des résultats de ce modèle, une preuve détaillée et suffisamment rigoureuse de la détermination de la variable de croissance « g » s'avère donc nécessaire. Les prévisions des analystes auxquelles il est fait référence ne pouvant être testées directement en audience, il est difficile de statuer sur le caractère raisonnable des estimés produits. De plus, l'hypothèse selon laquelle le facteur de croissance des dividendes peut être présumé égal à celui de la croissance nominale de l'économie ne

[47] Preuve de Mme McShane, pièce B-1, GI-4, document 1, page 57.

repose pas sur une évaluation détaillée et spécifique au présent dossier, mais sur une approche qui serait couramment utilisée dans le milieu financier. Comme ces diverses hypothèses sont déterminantes quant aux résultats de ce modèle, une preuve plus élaborée devrait être produite à cet égard.

Conclusion sur les autres modèles et autres considérations

[238] Pour l'ensemble de ces considérations, les résultats produits par les autres modèles sont utilisés au présent dossier mais leur utilité aux fins de la détermination d'un taux de rendement raisonnable est limitée.

[239] Même s'il est préférable, notamment dans un contexte comme celui qui prévaut actuellement, de pouvoir baser la détermination du taux de rendement de l'actionnaire sur un large éventail d'approches, je conclus, comme mes collègues, que l'utilisation du MÉAF apparaît, au présent dossier, l'approche de référence la plus fiable.

[240] Globalement, considérant le fait qu'aucun modèle ne peut représenter complètement et correctement à lui seul les attentes des investisseurs, un ajustement variant entre 10 et 50 points de base de la fourchette des résultats produits par le MÉAF peut être retenu.

[241] Aux fins de mon appréciation, considérant l'ensemble des motifs exprimés, je retiens la partie inférieure de la plage ainsi établie.

Taux de rendement d'un distributeur repère

[242] Sur la base de ce qui précède, le taux de rendement établi pour un distributeur repère, incluant les frais d'émission, peut être situé dans une fourchette variant entre 8,10 % et 9,51 %. Ce résultat sert de guide dans l'appréciation du rendement à octroyer à Gazifère.

Risque additionnel de Gazifère

[243] Aux fins de l'établissement du rendement de Gazifère, je juge l'ajustement proposé par Mme McShane raisonnable.

[244] En termes de risque d'affaires, le développement de l'entreprise dans les marchés résidentiels et d'affaires s'est poursuivi au cours des derniers dix ans tel qu'il pouvait l'être anticipé. La base de revenus stables de l'entreprise s'est donc renforcée.

[245] La perte récente de grands clients industriels constitue, toutes choses étant égales par ailleurs, un point négatif. Toutefois, la preuve révèle que cette perte est attribuable principalement aux difficultés d'ordre structurel dans un secteur précis d'activité économique et qu'elle ne résulte pas, par exemple, d'une dégradation de la compétitivité du gaz naturel. Enfin, la perte de marge brute y reliée n'affecte pas de façon indue le niveau des tarifs qui en résultent pour les autres usagers.

[246] Par ailleurs, le fait que Gazifère est une entreprise dont la taille ne lui permettrait pas d'accéder en propre aux marchés financiers et que sa notation, le cas échéant, serait vraisemblablement établie à BBB doit être pris en considération.

[247] Pour ces motifs, l'ajustement proposé de 50 points de base apparaît justifié.

[248] Enfin, l'argument du D^{r} Booth concernant le fait que les coûts qui découlent de la petite taille de Gazifère ne devraient pas être facturés aux consommateurs, bien que soulevant un enjeu d'intérêt sur le plan des principes réglementaires, ne peut être retenu dans la mesure où le cadre réglementaire existant de Gazifère repose sur le concept de l'isolement. Une application substantiellement différente de ce concept constitue un enjeu de portée très large dépassant le cadre de la présente audience.

Taux de rendement de Gazifère pour 2011

[249] Sur la base de ce qui précède et d'un taux sans risque de 4,25 %, le rendement de Gazifère peut être situé à l'intérieur d'une plage variant entre 8,60 % et 10,01 %.

Tableau 3
Fourchette d'un rendement raisonnable sur l'avoir de l'actionnaire pour Gazifère selon l'opinion minoritaire

	Bas %	Haut %
MÉAF		
1) Taux sans risque	**4,25**	**4,25**
2) Prime risque marché (moyennes arithmétiques/données historiques)	5,50	5,75
3) Bêta brut (marché = 1,00)	*0,50*	*0,55*
4) Prime risque distributeur repère (4 = 3*2)	**2,75**	**3,16**
5) Frais émission	**0,30**	**0,50**
6) Sous-total: distributeur repère selon MÉAF avant ajustement	**7,30**	**7,91**
7) Prime de risque du distributeur repère et taux sans risque courant	**0,40**	**0,50**
8) Prime de risque du distributeur repère et écarts de crédit courants	**0,30**	**0,60**
9) Sous-total: distributeur repère selon MÉAF ajusté	**8,00**	**9,01**
Autres modèles		
10) Autres modèles et autres considérations	**0,10**	**0,50**
Distributeur repère		
11) Sous-total: distributeur repère	**8,10**	**9,51**
Gazifère		
12) Risque additionnel GI	**0,50**	**0,50**
13) Total Gazifère (13=11+12)	**8,60**	**10,01**

[250] Pour l'ensemble des motifs exprimés dans mon opinion, les décisions antérieures de la Régie et le contexte dans lequel évolue le distributeur, je fixerais le rendement raisonnable sur l'avoir de l'actionnaire de Gazifère à 9,40 %.

Formule d'ajustement

[251] Mme McShane propose une nouvelle formule d'ajustement du taux de rendement comportant un facteur d'élasticité inverse de 0,50 pour toute variation future du taux sans risque ainsi qu'un facteur d'élasticité de 0,50 pour toute variation future des écarts de crédit corporatif.

[252] Le Dr Booth propose une formule identique, à l'exception du facteur d'élasticité du taux sans risque qui serait maintenu à 0,75 comme dans la formule existante.

[253] La proposition de Mme McShane est basée sur deux tests. Le premier utilise les rendements alloués par les régulateurs aux États-Unis entre 1995 et 2009 aux fins d'établir les facteurs d'élasticité. Le second test utilise les résultats de la méthode prime de risque établis à l'aide du modèle AFM.

[254] Ces deux tests sont basés sur l'utilisation directe ou indirecte de données provenant du secteur réglementé et s'appuient sur des données américaines. Ceci explique possiblement pourquoi les résultats de la formule proposée reproduisent de plus près l'évolution des rendements alloués aux États-Unis plutôt que celle des rendements alloués au Canada au cours de la période étudiée.

[255] À cet égard, la disponibilité de données et d'analyses portant sur l'élasticité des rendements sur l'équité en lien avec le taux sans risque et les écarts de crédit, mais portant sur des secteurs d'activité autres que les secteurs réglementés, serait possiblement utile.

[256] Par ailleurs, le Dr Booth est d'accord, de façon subsidiaire, avec l'introduction dans la formule d'ajustement d'un second terme représentant l'élasticité de la prime de risque implicite avec l'évolution des écarts de crédit corporatif.

[257] Comme mes collègues, je conclus qu'il est justifié de retenir un tel ajustement à partir de l'exercice 2012. Ceci permettra un ajustement plus rapide de la prime de risque implicite du distributeur en cas de variation substantielle des écarts de crédit dans le futur.

Cet ajustement s’appliquera également de façon symétrique à la hausse ou à la baisse, ce qui vient compléter l’ajustement de base au MÉAF retenu précédemment pour les écarts de crédit courants.

[258] Compte tenu de ces motifs et de l’introduction d’un second terme dans la formule, je conclus qu’il y a lieu de maintenir inchangé, au présent dossier, le facteur d’élasticité relié au taux sans risque.

[259] Ainsi déterminés, il est permis de présumer que ces deux termes pourraient se compenser mutuellement en cas de situations extrêmes, les écarts de crédit ayant généralement tendance à augmenter en situation de fortes diminutions du taux sans risque et inversement. Les résultats produits par la nouvelle formule pourront faire l’objet d’un examen au plus tard après quatre années d’application, soit en temps opportun pour l’exercice débutant en 2016.

[260] Je retiens donc, comme mes collègues, la formule d’ajustement établie pour 2012 et les années suivantes, telle qu’explicitée à l’annexe 1.

3. PLAN D’APPROVISIONNEMENT GAZIER POUR L’EXERCICE 2011 (PHASE 4)

[261] Gazifère n’a pas de service d’approvisionnement gazier, mais planifie, comme par le passé, être approvisionnée par son unique fournisseur de gaz naturel, EGD, qui lui fournit le gaz naturel sous le Tarif 200 établi par la CÉO.

[262] Le Tarif 200, introduit le 1er octobre 1991, est un tarif de service en gros s’appliquant à tout distributeur désirant transporter le gaz naturel dans le système de distribution d’EGD vers différents territoires à l’extérieur de la franchise de cette

dernière. Le 1er octobre 1991, Gazifère a conclu une entente avec EGD pour refléter l'introduction du Tarif 200 qui, depuis, se renouvelle d'année en année, à moins qu'une des deux parties y mette fin. Gazifère obtient donc tous ses services d'approvisionnement d'EGD par le biais du Tarif 200, soit :

- la fourniture du gaz naturel;
- le transport sur TransCanada PipeLines Limited (TCPL);
- l'équilibrage.

[263] Le Tarif 200 permet aussi à Gazifère d'offrir, dès l'année témoin 1991-1992, le service de livraison à ses clients. EGD accepte de céder de façon temporaire sa capacité sur TCPL aux clients de Gazifère qui optent pour le service de livraison.

[264] En date du 1er octobre 1991, Gazifère a signé un contrat de transport avec Niagara Gas Transmission (Niagara) afin de transporter le gaz naturel de l'Ontario au Québec. La base de facturation pour ce service est le coût de service de Niagara tel que reconnu par l'ONÉ.

[265] Ces deux contrats d'approvisionnement gazier et de transport ont été approuvés par la Régie du gaz naturel dans sa décision D-92-28[48].

[266] Gazifère soumet que son approvisionnement gazier au Tarif 200 répond à tous ses besoins, tels que présentés pour les années 2011 à 2013 au tableau suivant[49].

48 Dossier R-3230-92.
49 Pièce B-29, GI-33, document 1.

Tableau 4
Approvisionnements gaziers (10^3m^3)

Secteurs	**2011**	**2012**	**2013**
Résidentiel	67 827	69 019	70 211
Commercial	65 604	66 259	66 915
Industriel	28 346	28 346	28 346
Programme d'efficacité énergétique résidentiel	(4 661)	(5 000)	(5 339)
Programme d'efficacité énergétique commercial	(2 028)	(2 266)	(2 504)
Total	**155 088**	**156 359**	**157 630**

[267] L'ACIG appuie les demandes de Gazifère[50].

[268] La FCEI remet en question le niveau proposé par le distributeur pour la projection de la demande en 2011 de ses clients industriels en service interruptible, soit les clients au tarif 9. Elle conteste donc le plan d'approvisionnement proposé par ce dernier[51].

[269] La Régie constate que tous les clients au tarif 9 de Gazifère sont des clients en service de livraison qui fournissent leur propre transport et leur propre fourniture de gaz naturel. Une augmentation de la demande de ces clients se traduira par une faible augmentation des volumes de gaz naturel non facturé et non comptabilisé du distributeur et n'aura pas d'impact sur la demande contractuelle que ce dernier contracte auprès d'EGD[52].

[270] La Régie considère que les besoins en approvisionnement de Gazifère sont adéquatement comblés par EGD, selon les modalités du Tarif 200 et que le plan d'approvisionnement de Gazifère satisfait aux exigences du *Règlement sur la teneur et la*

[50] Pièce A-49-3, page 77.
[51] Pièce A-49-3, page 61.
[52] Pièce A-49-1, pages 109 et 110; pièce B-49, GI-41, document 2, réponse1.1; pièce B-49, GI-41, document 2.1, colonne « *Comments* ».

périodicité du plan d'approvisionnement. Elle traitera du niveau de la prévision de la demande des clients au tarif 9 du distributeur à la section 5 de la présente décision.

[271] **En conséquence, la Régie approuve le plan d'approvisionnement de Gazifère pour l'exercice 2011, sous réserve de sa décision quant au niveau de la prévision de la demande des clients au tarif 9 du distributeur.**

4. REVENUS REQUIS DE DISTRIBUTION DE 2011 (PHASE 4)

4.1 APPLICATION DU MÉCANISME INCITATIF

[272] Gazifère a calculé le revenu requis de distribution pour l'année témoin 2011 en appliquant la formule et les paramètres du mécanisme incitatif approuvés par la Régie en Phase 1 du présent dossier[53]. Le distributeur établit ce revenu requis à 23 523 400 $, ce qui représente une augmentation moyenne de 0,9 % des tarifs de distribution[54].

[273] Le revenu requis de distribution de l'année 2010 utilisé dans le cadre de la formule d'ajustement du revenu pour l'année 2011 correspond au revenu requis approuvé par la Régie dans sa décision D-2009-151 au montant de 22 875 900 $[55]. Ce montant est ajusté à la baisse pour tenir compte des comptes différés, de l'amortissement des comptes de stabilisation, de l'exclusion relative au nouveau système d'information client (système CIS) et de la part des clients de l'excédent de rendement de l'année 2009. Par la suite, Gazifère a réduit ce montant de 853 400 $ pour ajuster de façon globale le revenu requis de base conformément aux décisions de la Régie. Le revenu requis de distribution de l'année de base 2010 ainsi calculé se chiffre à 20 401 800 $. Ce montant est utilisé pour déterminer le revenu requis de distribution de l'année 2011 selon la formule d'ajustement approuvée par la Régie[56].

53 Décisions D-2010-112 et D-2010-112R.
54 Pièce B-41, GI-35, document 1.
55 Dossier R-3692-2009 Phase 3.
56 Pièce B-41, GI-35, document 2.

[274] Gazifère prévoit desservir 37 407 clients en moyenne au cours de l'année témoin 2011, soit une augmentation de 1 041 clients ou 2,8 % par rapport au nombre moyen de clients prévus pour 2010. La Régie constate que le nombre moyen de clients prévus en 2010, incluant les données réelles jusqu'au 31 juillet, est sensiblement le même que celui qu'elle a approuvé pour cette année[57]. Elle constate également que cette augmentation correspond au nombre de nouveaux clients que le distributeur compte desservir avec ses projets d'extension et de modification du réseau en 2011. La Régie est satisfaite des explications du distributeur relatives à ses projections d'additions des clients[58]. Elle note également l'ajout d'un nouveau client industriel au tarif 1 en 2010[59]. La Régie accepte la prévision de Gazifère du nombre moyen de clients pour l'année témoin 2011.

[275] Par ailleurs, la Régie constate que Gazifère utilise le taux nominal d'impôt dans le calcul de l'ajustement du coût du capital (facteur « R »)[60] conformément à la décision de la Régie. Les exclusions de l'année 2011 totalisent 2 888 200 $ et Gazifère ne propose aucun facteur exogène pour cette même année.

[276] Gazifère a réduit le revenu requis de distribution pour l'année témoin 2011 de 1 318 200 $, soit la part de l'excédent de rendement de l'année témoin 2009, incluant les intérêts qui reviennent aux clients, conformément à la décision D-2010-112 de la Régie[61].

[277] Gazifère établit son revenu requis de distribution de l'année 2011 en utilisant un taux de rendement sur l'avoir de l'actionnaire de 11,25 %, tel que recommandé par son témoin expert dans le cadre de la Phase 2 du présent dossier[62].

[278] La Régie constate que le distributeur a calculé le revenu additionnel requis pour l'année témoin 2011 conformément à ses exigences, à la formule d'ajustement du revenu de distribution et aux paramètres du mécanisme incitatif qu'elle a approuvés pour la période du 1er janvier 2011 au 31 décembre 2015[63]. **Elle s'attend à ce que Gazifère ajuste le calcul des exclusions reliées aux projets d'investissements de plus de 450 000 $, notamment les projets CIS et Chemin Pink, pour refléter le taux de rendement sur l'avoir de l'actionnaire qu'elle fixe pour l'année tarifaire 2011.**

57 Pièce B-43, GI-41, document 1, réponse 1.1.
58 Pièce B-43, GI-41, document 1, réponse 1.3.
59 Pièce A-49-1, pages 94 à 97.
60 Pièce B-41, GI-35, document 2.2.
61 Dossier R-3724-2010 Phase 3.
62 Pièce B-1, GI-4, document 1.
63 Décision D-2010-112 et D-2010-112R, dossier R-3724-2010 Phase 1.

[279] **La Régie approuve les paramètres utilisés et le calcul fait par Gazifère pour établir le revenu requis de distribution pour l'année témoin 2011, sous réserve de la mise à jour du taux de rendement sur l'avoir de l'actionnaire correspondant à la présente décision, et sujets aux modifications à apporter à l'ensemble des éléments découlant de la présente décision.**

4.2 EXCLUSIONS

[280] Gazifère demande d'approuver les soldes des comptes suivants et de l'autoriser à inclure ces charges dans l'établissement du revenu requis à titre d'exclusion.

Tableau 5

Exclusions pour lesquelles Gazifère demande une autorisation[64]

Charges réglementaires 2011	175 000 $
Charges réglementaires – compte d'écart 2009	16 032 $
PGEÉ 2011	544 067 $
PGEÉ – compte d'écart 2009	(28 495 $)
Quote-part à l'AEÉ 2011	21 563 $
Quote-part à l'AEÉ – compte d'écart 2009	(34 446 $)
Mécanisme incitatif axé sur le PGEÉ 2011	79 000 $
Fonds CASEP	75 000 $

[281] **La Régie approuve les montants et permet l'inclusion des exclusions « *Charges réglementaires* », « *PGEÉ* » et « *Quote-part à l'AEÉ* » ainsi que des comptes d'écart liés à ces postes dans le calcul du revenu requis.**

64 Pièce B-35, GI-35, document 2.3.1, page 1; pièce B-41, GI-35, document 2.3, page 1.

[282] En ce qui a trait aux charges réglementaires et au plan global en efficacité énergétique (PGEÉ), la détermination des montants découle de l'utilisation de la comptabilité d'exercice. Pour ce qui est de la quote-part à l'AEÉ, cette exclusion est liée à la facture du premier trimestre 2011. Les comptes d'écart servent à tenir compte des variations entre les sommes budgetées et les sommes réelles encourues.

[283] La Régie traitera des exclusions « *Mécanisme incitatif axé sur le PGEÉ* » et « *Fonds CASEP* » aux sections 8.4 et 8.5 de la présente décision.

4.3 COMPTE DE STABILISATION DU GAZ NATUREL PERDU

4.3.1 ÉVALUATION DU GAZ NATUREL PERDU

[284] Dans sa décision D-2009-151, la Régie demandait à Gazifère de faire rapport au présent dossier tarifaire sur les travaux de développement de nouveaux outils pour estimer en temps opportun le gaz naturel non facturé à chaque fin de mois, à la suite de l'implantation de son système CIS[65].

[285] Gazifère informe la Régie que le système CIS a été implanté le 14 septembre 2009. Toutefois, elle précise que certaines fonctionnalités prévues initialement et certaines interfaces non essentielles à la facturation n'étaient pas disponibles lors de cette implantation. Ce n'est qu'au mois de mars 2010 qu'elle a élaboré un plan afin de prioriser les fonctionnalités qui n'avaient pas été livrées, le développement d'interfaces et la réparation de certaines fonctionnalités inadéquates. Elle estime que toutes les fonctionnalités manquantes seront complétées à la fin de l'année 2010.

[286] Gazifère indique que l'année 2010 a été une période de stabilisation du système CIS et d'apprentissage pour les usagers et soumet que le développement de nouveaux outils pendant cette période instable n'aurait pas été productif et prudent dans les circonstances.

[65] Dossier R-3692-2009 Phase 3, page 20.

[287] Gazifère indique qu'elle sera en mesure de poursuivre ses démarches pour trouver la meilleure solution pour le calcul mensuel du gaz naturel non facturé lorsque son système CIS sera pleinement opérationnel. Elle s'engage à faire un suivi à cet égard dans le cadre de son prochain dossier tarifaire[66].

[288] **La Régie est satisfaite des explications fournies par Gazifère et prend acte du fait que cette dernière lui fera rapport sur le développement de nouveaux outils pour estimer en temps opportun le gaz naturel non facturé dans le prochain dossier tarifaire.**

4.3.2 TAUX DE GAZ NATUREL PERDU

[289] Conformément aux demandes de la Régie[67], Gazifère exclut le taux de gaz naturel perdu de l'année 2005, jugé non représentatif par rapport aux autres années, et utilise un taux de gaz naturel perdu de 1,13 % provenant de causes non mesurables en 2009 pour calculer la moyenne mobile de cinq ans[68].

[290] **La Régie est satisfaite du calcul de la moyenne mobile de cinq ans effectué par le distributeur et approuve un taux de gaz naturel perdu de 0,91 % pour l'année témoin 2011.**

5. PRÉVISION DE LA DEMANDE DE GAZ NATUREL (PHASE 4)

[291] Gazifère prévoit que 155,1 millions de mètres cubes de gaz naturel seront consommés en 2011. Cette prévision est basée sur une estimation de 63,2 millions de mètres cubes pour le secteur résidentiel, de 63,6 millions de mètres cubes pour le secteur commercial et de 28,3 millions de mètres cubes pour le secteur industriel[69].

66 Pièce B-35, GI-34, document 1, réponse R.16.
67 Décision D-2008-144, dossier R-3665-2008 Phase 2, page 21; décision D-2010-112, dossier R-3724-2010 Phase 3, page 21.
68 Pièce B-35, GI-40, document 2.2.
69 Pièce B-35, GI-36, document 1.

[292] Gazifère soumet que sa projection volumétrique est établie selon les principes qu'elle a toujours utilisés, tant au niveau des services en continu qu'au niveau du service interruptible, soit à partir des contrats signés par les clients[70].

[293] Gazifère prévoit une demande de 8 674 300 m^3 en 2011 pour deux clients industriels au tarif 9[71]. La prévision est basée sur les derniers contrats signés à ce jour par ces deux clients. Le distributeur précise qu'il n'est pas en discussion avec d'autres clients potentiels en service interruptible[72].

[294] La FCEI note des écarts importants entre les prévisions et les volumes réels au tarif 9 du distributeur depuis 2007 et que ces écarts varient d'environ 20 à 30 millions de mètres cubes. Selon elle, ces écarts de prévision ont pour effet de faire supporter à la clientèle du distributeur des coûts annuels indus de l'ordre de 150 000 $ à 220 000 $ pour les années 2007 à 2009, tenant compte de leur impact sur l'excédent de rendement du distributeur et sur le taux du Tarif 200 d'EGD. L'intervenante soumet que l'exercice de prévision des volumes du tarif 9 du distributeur présente encore aujourd'hui les mêmes lacunes qu'au cours des dernières années et que, selon elle, tout porte à croire que le coût indu correspondant pour l'exercice 2011 sera du même ordre si la prévision du distributeur est maintenue telle quelle. La FCEI recommande à la Régie, dans le cadre du présent dossier, de revoir à la hausse la prévision de demande pour le tarif 9 de Gazifère et de l'établir à 32 962 000 m^3, soit 3,8 fois le niveau proposé par le distributeur[73]. L'intervenante reconnaît toutefois que le distributeur sera à risque si les volumes de ventes ne se réalisent pas[74].

[295] La FCEI propose également qu'une révision de la méthode de prévision des volumes interruptibles soit l'objet d'un examen lors du prochain dossier tarifaire[75].

70 Pièce A-49-1, page 101.
71 Pièce B-35, GI-36, document 1, ligne 21.
72 Pièce B-43, GI-43, document 1, réponses 1.4 à 1.6.
73 Pièce C-3-25, pages 3 à 7.
74 Pièce A-49-2, page 106.
75 Pièce A-49-3, pages 35 à 37.

[296] Gazifère est en désaccord avec la recommandation de la FCEI. Elle souligne qu'elle a toujours utilisé les derniers contrats signés par les clients au tarif 9 au moment d'établir les projections volumétriques de cette clientèle et qu'il s'agit d'une pratique reconnue dans l'industrie à cet égard. Gazifère soumet qu'il doit y avoir une réciprocité absolue entre les contrats signés et le niveau des volumes qu'elle utilise pour établir ses tarifs[76]. De plus, la référence au contrat constitue, selon elle, la façon prudente de prévoir les volumes, notamment dans le cas des clients en service interruptible qui peuvent changer d'une source d'énergie à l'autre selon la situation concurrentielle[77].

[297] Gazifère souligne également qu'elle n'est plus du tout dans le même contexte que celui qui prévalait durant la période de 2007 à 2009 et que le niveau de volume recommandé par la FCEI n'a été atteint qu'une seule fois en 2008. De plus, elle indique que, sur les deux clients en service interruptible prévus pour 2011, il y a une probabilité que celui qui s'est placé sous la protection de la *Loi sur les arrangements avec les créanciers des compagnies*[78] ferme son usine à la fin de 2010[79]. Elle soumet donc que la situation actuelle n'est pas propice pour changer de méthode de prévision des volumes et qu'il serait imprudent de se baser sur les données historiques pour établir les prévisions volumétriques[80].

[298] Gazifère soumet qu'elle s'expose à un risque, qu'elle considère inacceptable, s'il n'y a pas de réciprocité ou d'adéquation entre les contrats et la projection volumétrique. Elle souligne qu'au surplus, son mécanisme incitatif ne la protège pas en cas de manque à gagner. Gazifère souhaite donc que la méthode utilisée pour établir les projections volumétriques des clients au tarif 9 soit maintenue[81].

[299] Selon l'ACIG, la recommandation de la FCEI d'introduire un facteur multiplicateur pour prévoir la demande des clients au tarif 9 du distributeur s'écarte de la méthode habituelle utilisée par Gazifère, soit celle qui s'en remet au volume contractuel prévu dans les contrats signés avec les clients. L'intervenante soumet que cette recommandation, même pour un an, correspondrait à revoir de façon générique la

[76] Pièce A-49-1, pages 105, 106, 108 et 109.
[77] Pièce A-49-1, pages 65, 66, 73 et 74.
[78] L.R.C., 1985, c. C-36.
[79] Pièce B-49, GI-41, document 2.
[80] Pièce A-49-3, pages 9 à 11; pièce B-49, GI-41, document 2.
[81] Pièce A-49-1, page 109; pièce A-49-3, pages 12 à 14.

méthode visant à déterminer les volumes et, par conséquent, serait contraire à la décision D-2010-112 de la Régie[82]. Par ailleurs, l'ACIG est d'avis que cet enjeu devrait faire l'objet d'un examen dans le cadre du prochain dossier tarifaire[83].

[300] La Régie rappelle que, dans le cadre de la Phase 1 du présent dossier, l'ACIG remettait en question la provenance des excédents de rendement réalisés par Gazifère depuis la mise en place du mécanisme incitatif[84] et reliait ces excédents de rendement aux écarts importants de volumes entre la prévision et les ventes réelles au service interruptible. C'est dans ce contexte, et considérant les explications de Gazifère sur l'impact tarifaire des erreurs de prévision[85], que la Régie statuait qu'il n'y avait pas lieu de modifier de façon générique la méthode de prévision des volumes interruptibles. Elle indiquait cependant que les projections volumétriques pouvaient être examinées dans le cadre des dossiers tarifaires annuels, tout comme les autres éléments pouvant faire l'objet d'une projection[86].

[301] Dans le cadre de la Phase 4 du présent dossier, la Régie réitère qu'il n'y a pas lieu de modifier de façon générique la méthode de prévision employée par Gazifère. Toutefois, la Régie peut exercer son jugement en vue de retenir une projection vraisemblable pour la clientèle du distributeur, car cette projection a un impact direct sur l'établissement des tarifs de distribution en début d'année.

[302] La Régie considère que la méthode utilisée par Gazifère pour effectuer ses prévisions de demande en 2011 pour la clientèle en service continu donne des résultats acceptables. Elle constate, toutefois, que la prévision du distributeur pour sa clientèle en service interruptible, basée sur les derniers contrats signés, est largement sous-estimée par rapport aux consommations réelles récentes de cette clientèle en 2009 et en 2010[87]. Elle note également qu'une telle sous-estimation a un impact à la hausse sur tous les tarifs du distributeur en début d'année[88]. La Régie juge donc qu'il y a lieu d'ajuster à la hausse la prévision de la demande des clients au tarif 9 du distributeur pour l'exercice 2011.

[82] Pièce A-49-3, page 78.
[83] Pièce A-49-3, pages 77 à 80.
[84] Pièce C-2-14, section 5.
[85] Pièce B-21, GI-6, document 3, réponse de Gazifère à l'engagement n° 2, page 4; pièce A-26-4, page 47.
[86] Décision D-2010-112, dossier R-3724-2010 Phase 1.
[87] Pièce B-43, GI-43, document 1, réponses 1.4 et 1.5.
[88] Pièce B-49, GI-41, document 2.2.

[303] La Régie ne retient pas la proposition de la FCEI d'appliquer un facteur multiplicateur de 3,8 au niveau de demande proposé par Gazifère parce que cette proposition ne tient pas compte du contexte dans lequel évolue le distributeur[89].

[304] Pour l'exercice 2011, la Régie est d'avis que la position concurrentielle du gaz naturel par rapport aux autres formes d'énergie ne devrait pas être très différente de celle qui prévaut en 2010. **Tenant compte du contexte de marché du distributeur et de ses anticipations de ventes réelles en 2010[90], la Régie fixe à 13 674 300 m^3 le niveau raisonnable de projection de la demande de ses clients au tarif 9 pour l'exercice 2011**.

[305] La Régie établit ce niveau de projection comme suit :

- consommation estimée de 2 000 000 m^3 pour le client qui s'est placé sous la protection de la *Loi sur les arrangements avec les créanciers des compagnies*, soit au niveau de son dernier contrat signé;
- consommation estimée de 11 674 300 m^3 pour le deuxième client, soit environ 75 % des volumes réels de 15 559 300 m^3 anticipés par Gazifère pour ce client en 2010.

[306] La Régie considère qu'en établissant le niveau de prévision de 2011 à environ 57 % de la consommation réelle totale de 23 867 900 m^3 anticipée par Gazifère pour ses deux clients au tarif 9 en 2010, elle n'impose pas à cette dernière un risque indu.

[307] **La Régie acquiesce à la demande de la FCEI et de l'ACIG et reporte l'examen de la méthode de prévision de la demande de la clientèle au tarif 9 du distributeur au prochain dossier tarifaire.**

[89] Pièce A-49-2, pages 108 à 111.
[90] Pièce B-43, GI-43, document 1, réponses 1.4 et 1.5.

6. INVESTISSEMENTS RELIÉS AUX PROJETS D'EXTENSION ET DE MODIFICATION DU RÉSEAU INFÉRIEURS À 450 000 $ (PHASE 4)

[308] Gazifère présente, au tableau suivant, ses dépenses prévisionnelles reliées aux projets d'extension et de modification du réseau de moins de 450 000 $ ne nécessitant pas d'approbation individuelle[91].

Tableau 6
Projets d'extension et de modification du réseau

Branchements d'immeubles	2 378 400 $
Conduites principales	2 845 400 $
Postes de mesurage	98 000 $
Compteurs	347 100 $
Sous-total	5 668 900 $
Contributions	(29 300 $)
Total	**5 639 600 $**

[309] Pour l'année 2011, la réalisation de ces projets devrait permettre à Gazifère de desservir 1 237 nouveaux clients, avec des investissements en capital de 4 360 300 $ liés aux additions de clients. Le solde des investissements en capital prévus de 1 279 300 $ est lié à l'entretien du réseau.

[310] Le résultat de l'analyse de rentabilité est positif, puisqu'il démontre que ces investissements dégagent une valeur actuelle nette (VAN) de 2 863 572 $ et un taux de rendement interne (TRI) de 10,94 %[92].

[311] L'analyse de rentabilité effectuée par le distributeur est conforme aux exigences de la Régie[93].

91 Pièce B-35, GI-34, document 2.
92 Pièce B-35, GI-34, document 2.1.
93 Décision D-2006-58, dossier R-3587-2005 Phase 1; décision D-2006-158, dossier R-3587-2005 Phase 2.

[312] Gazifère présente l'évolution depuis 2006 des investissements en capital liés à l'addition de clients et des investissements liés à l'entretien. Elle présente également l'évolution, sur la même période, des coûts moyens des branchements liés aux additions des clients, les coûts moyens par kilomètre de conduites principales et les coûts des postes de mesurage et des compteurs. La Régie note que ces investissements et ces coûts présentent des variations raisonnables sur la période de 2006 et 2011. Elle est satisfaite des explications du distributeur à cet égard[94].

[313] L'ACEFO recommande à la Régie de demander au distributeur d'appliquer un indicateur d'investissements liés à l'entretien par kilomètre de conduites ou par valeur de l'actif du distributeur afin d'avoir une meilleure idée de la façon dont le distributeur évolue au niveau de son efficience et de voir s'il y a lieu pour ce dernier de faire des efforts supplémentaires[95]. La Régie note que l'intervenante présente sa recommandation pour la première fois lors de son argumentation, sans l'étayer ni dans son mémoire ni lors de la présentation de sa preuve en audience. Par ailleurs, l'objectif poursuivi par cette intervenante est imprécis, tenant compte du mécanisme incitatif de Gazifère. La Régie ne retient donc pas sa recommandation.

[314] **La Régie est satisfaite de l'analyse effectuée par Gazifère et de la rentabilité des investissements reliés aux projets d'extension et de modification du réseau du distributeur dont le coût de chacun des projets est inférieur à 450 000 $ et autorise les déboursés de 5 639 600 $ qui y sont reliés.**

7. MÉTHODE DE RÉCUPÉRATION DES REVENUS ADDITIONNELS REQUIS DE DISTRIBUTION (PHASE 4)

[315] Gazifère propose d'allouer son revenu de distribution de l'exercice 2011 par classe tarifaire selon la méthode d'allocation des coûts approuvée par la Régie dans sa décision D-2006-158[96].

94 Pièce B-43, GI-42, document 1.
95 Pièce A-49-3, pages 69 et 70.
96 Dossier R-3587-2005 Phase 2.

[316] Gazifère propose également de maintenir les obligations minimales mensuelles de ses tarifs de distribution à leur niveau de 2010. Elle justifie sa proposition en indiquant que les obligations minimales mensuelles de 2010, appliquées au nombre de clients ou volumes contractuels de l'exercice 2011, lui permettent d'obtenir sensiblement le même niveau de récupération des coûts fixes en raison de la faible augmentation proposée des tarifs de distribution[97].

[317] Le distributeur propose toutefois un ajustement à la hausse de 25 000 $ des revenus qui seront alloués au tarif 2 du service résidentiel et institutionnel et un ajustement à la baisse correspondant de 25 000 $ des revenus qui seront alloués au tarif 1 du service général. Il soumet que ces ajustements permettent d'améliorer le ratio revenu/coût (ratio R/C) du tarif 2 tout en maintenant celui du tarif 1 à son niveau de 2010. De plus, le distributeur précise que l'allocation qu'il propose permet également de maintenir le ratio R/C de son tarif 5 à son niveau de 2010 et d'améliorer les ratios R/C de ses tarifs 3 et 9[98].

[318] Gazifère explique le mode de répartition qu'elle a retenu pour chacune des composantes de l'ajustement global de -833 400 $ de son revenu requis de l'année de base 2010[99], conformément à la demande de la Régie[100].

[319] La Régie est satisfaite du mode de répartition proposé par Gazifère. Elle est également satisfaite des explications du distributeur relatives à sa proposition de maintien des obligations minimales mensuelles des tarifs de distribution à leur niveau de 2010.

[320] La Régie constate que les ajustements tarifaires proposés par Gazifère pour l'année témoin 2011 améliorent les ratios R/C des tarifs 2, 3 et 9 et contribuent à maintenir ceux des tarifs 1 et 5 à leur niveau de 2010[101].

[321] La Régie note que Gazifère prévoit déposer une étude complète d'allocation des coûts lors du renouvellement de son mécanisme incitatif en 2014[102].

97 Pièce B-35, GI-39, document 1, réponse A.8.
98 Pièce B-35, GI-39, document 1, réponse A.7.
99 Pièce B-35, GI-38, document 1, réponse A.6; pièce B-43, GI-41, document 1, réponse 4.1.
100 Décision D-2010-112, dossier R-3724-2010 Phase 1.
101 Pièce B-35, GI-39, document 1, page 4, tableau 1.
102 Pièce A-49-1, pages 115 à 118.

[322] **La Régie approuve la méthode proposée par Gazifère pour récupérer ses revenus additionnels requis de distribution en 2011. Considérant les impacts tarifaires des ajustements proposés et afin de lui permettre de faire un suivi régulier de l'interfinancement entre les tarifs, la Régie demande au distributeur de déposer, à partir du prochain dossier tarifaire, le calcul des ratios R/C pour chaque classe tarifaire, tel que présenté au tableau 1 de la pièce B-35, GI-39, document 1.**

8. BUDGETS VOLUMÉTRIQUE ET MONÉTAIRE DU PGEÉ (PHASE 4)

8.1 RÉSULTATS AU 30 JUIN 2010

[323] Gazifère dépose les résultats du PGEÉ pour les six premiers mois de l'année témoin 2010[103] conformément à la demande de la Régie dans la décision D-2006-158[104].

[324] La Régie constate que Gazifère évalue les économies d'énergie réelles en multipliant le nombre de participants réel (net d'opportunisme) par l'économie unitaire basée sur le cas type établi pour le programme. Pour le secteur résidentiel, cette façon de faire ne pose pas de problème. En effet, ce marché étant assez homogène, il est propable qu'en moyenne, un participant à un programme ait une consommation similaire à celle du cas type.

[325] Dans le secteur commercial, en raison de la diversité de la clientèle, le cas type n'est pas nécessairement représentatif. D'ailleurs, en réponse à une demande de renseignements de la Régie, Gazifère présente les consommations réelles moyennes des participants aux différents programmes commerciaux pour les six premiers mois de 2010[105]. La comparaison de ces données réelles avec celles des cas types des programmes[106] montre que les participants réels ont des consommations beaucoup plus faibles que les participants types. Ce constat ne s'applique cependant pas au programme « *Chauffe-eau efficace – petit réservoir* ».

103 Pièce B-43, GI-37, documents 2 et 3.
104 Dossier R-3587-2005 Phase 2.
105 Pièce B-44, GI-41, document 1, page 20.
106 Pièce B-35, GI-37, document 1, page 51.

[326] La Régie considère que les économies réelles rapportées par le distributeur doivent, autant que possible, refléter la réalité. Elle reconnaît que certains éléments des cas types ne peuvent être revus qu'en évaluation. C'est effectivement le cas pour le taux d'opportunisme et le pourcentage d'économies que le programme permet d'obtenir. Par contre, sans avoir fait d'évaluation, les résultats d'une année permettent d'obtenir, outre le nombre de participants, la consommation réelle de ces participants (normalisée pour la température) et le coût réel du programme.

[327] Les économies unitaires d'un programme d'efficacité énergétique représentent, règle générale, un pourcentage de la consommation du participant pour l'usage auquel le programme s'adresse. Par exemple, l'utilisation d'un chauffe-eau à condensation amènera une réduction de la consommation pour le chauffage de l'eau qui sera un pourcentage de la consommation habituelle liée à cet usage. En utilisant un chauffe-eau à condensation, un participant ayant une importante consommation associée au chauffage de l'eau économisera un volume de gaz naturel plus grand que celui qui a une consommation plus faible pour ce même usage.

[328] **Compte tenu de l'écart constaté entre la consommation totale réelle des participants aux programmes commerciaux de Gazifère en 2010 et la consommation totale attendue dans les cas types, la Régie demande à Gazifère de revoir les économies volumétriques réelles des programmes commerciaux présentées pour les six premiers mois de 2010. Elle demande au distributeur de déposer les résultats corrigés au plus tard le 10 décembre 2010 à 12 h.**

8.2 APPROBATION DES BUDGETS VOLUMÉTRIQUE ET MONÉTAIRE

[329] Le PGEÉ 2011 comporte 16 programmes [8 résidentiels et 8 commerciaux et institutionnels (CI)]. Les seuls changements par rapport à 2010 sont le retrait du programme « *Chauffe-eau instantané* » et l'ajout d'un programme « *Récupérateur de chaleur des eaux de douche – coopératives d'habitation et organismes à vocation sociocommunautaire* ».

[330] Gazifère soumet les projections suivantes pour 2011.

Tableau 7

Projections PGEÉ 2011 Gazifère

Programmes	**Économies totales m³**	**Aide financière totale ($)**
Secteur résidentiel		
Thermostats programmables – marché existant (achat)	13 028	7 392
Thermostats programmables – marché existant (location)	15 135	13 332
Thermostats programmables – marché existant (volet communautaire)	333	264
Trousse de produits économiseurs d'eau chaude (pomme de douche)	14 035	2 005
Trousse de produits économiseurs d'eau chaude (brise-jet)	2 526	1 203
Trousse de produits économiseurs d'eau chaude (isolant)	2 246	401
Trousse de produits économiseurs d'eau chaude (abaissement temp. chauffe-eau)	54 960	0
Chauffe-eau efficace (location)	119 284	0
Récupérateur de chaleur des eaux de douche	2 600	2 000
Chaudière à efficacité supérieure (achat)	1 580	2 500
Chaudière à efficacité supérieure (location)	1 580	2 500
Aide financière à la rénovation–Coop. d'habitation et organismes à vocation sociocommunautaire	28 810	57 620
Récupérateur de chaleur des eaux de douche–Coop.d'habitations et organismes à vocation sociocommunautaire	22 000	77 000
Sous-total résidentiel	278 117	166 217
Secteur commercial et institutionnel (C&I)		
Appui aux initiatives – Optimisation énergétique des bâtiments	91 076	40 000
Chauffe-eau efficace (petit réservoir)	490	0
Chauffe-eau efficace (grand réservoir)	15 400	0
Chaudière à efficacité intermédiaire (achat)	27 557	16 500
Chaudière à efficacité intermédiaire (location)	16 534	9 900
Chauffe-eau à efficacité intermédiaire (achat)	9 142	3 000
Chauffe-eau à efficacité intermédiaire (location)	6 094	2 000
Chauffe-eau à condensation (achat)	11 821	6 000
Chauffe-eau à condensation (location)	11 821	6 000
Chaudière à condensation (achat)	52 154	30 000
Chaudière à condensation (location)	15 646	9 000
Étude de faisabilité	29 939	4 000
Unité de chauffage à l'infrarouge	14 699	2 450
Sous-total C&I	302 372	128 850
Total programmes	580 489	295 067
Autres frais		244 000
Évaluation		5 000
Grand total	580 489	544 067

[331] Le budget global du PGEÉ de Gazifère passe de 448 227 $ en 2010 à 544 067 $ en 2011, ce qui représente une augmentation de 21 %. Les économies d'énergie prévues atteignent 580 489 m^3 par rapport à des prévisions de 502 107 m^3 en 2010, soit une augmentation de 16 %.

[332] Les budgets consacrés à la clientèle des ménages à faible revenu (MFR) atteignent 24,8 % du budget total du PGEÉ. Le budget pour la clientèle résidentielle, excluant les budgets spécifiques à la clientèle MFR, ne représente plus que 6 % du budget total, alors que cette proportion était de 18 % en 2010. Le tronc commun représente 47 % du PGEÉ, alors que cette proportion était de 46 % en 2010.

[333] **La Régie approuve le PGEÉ 2011, sous réserve des modifications demandées ci-après, et demande à Gazifère de déposer, au plus tard le 10 décembre 2010 à 12 h, selon le format du tableau 7, les budgets monétaire et volumétrique du PGEÉ intégrant ces modifications.**

[334] Gazifère dépose les cas types de tous les programmes du PGEÉ 2011[107]. Pour certains programmes, le distributeur propose d'utiliser les cas types du Fonds en efficacité énergétique (FEÉ) ou ceux du PGEÉ de Gaz Métro.

[335] La Régie constate que les participants types des programmes commerciaux de Gazifère consomment tous (sauf pour les programmes « *chauffage infrarouge* » et « *chauffe-eau à petit réservoir* ») plus de 100 000 m^3/an. En réponse à une demande de la Régie, le distributeur donne la répartition des clients commerciaux en fonction de leur consommation réelle[108]. La Régie note qu'il n'y a que 3,2 % de la clientèle commerciale de Gazifère qui consomme plus de 100 000 m^3/an. En fait, la très grande majorité des clients (82,5 %) consomme moins de 20 000 m^3/an.

[336] Les données de participation aux programmes commerciaux, pour les années 2008, 2009 et 2010, présentées par Gazifère en réponse à une demande de la Régie[109] tendent à démontrer, à quelques exceptions près, que la consommation des cas types des programmes du secteur commercial est trop élevée et n'est donc pas représentative de la consommation de la clientèle commerciale du distributeur.

[107] Pièce B-35, GI-37, document 1, pages 50 et 51.
[108] Pièce B-44, GI-41, document 1, page 19.
[109] Pièce B-44, GI-41, document 1, page 20.

[337] La Régie considère que les cas types des programmes du PGEÉ doivent refléter le plus possible les caractéristiques de consommation des clients du distributeur visés par les différents programmes. Ces cas types servent à prévoir l'impact du PGEÉ sur la demande que le distributeur devra approvisionner et ont donc un effet sur les tarifs.

[338] Même si l'utilisation des cas type de Gaz Métro peut être utile comme point de départ, ces cas type doivent être validés avec les données propres à Gazifère pour s'assurer de leur pertinence. **La Régie demande au distributeur de revoir les paramètres des cas types relatifs à la consommation des participants [consommation totale, consommation par usage et économie unitaire (en m^3)] à partir des données réelles de participation et des caractéristiques de la clientèle visée par les programmes du secteur CI. Elle lui demande également de déposer, au plus tard le 10 décembre 2010 à 12 h, une mise à jour des cas types et les prévisions [volumétriques, budgétaires et test du coût total en ressources (TCTR)] du PGEÉ 2011, ajustées en tenant compte de ces révisions.**

8.3 ANALYSE ÉCONOMIQUE DES PROGRAMMES

[339] Globalement, le TCTR du PGEÉ est positif. La faible valeur des coûts évités a pour résultat que certains programmes existants affichent un TCTR négatif pour 2011. Ce sont, au secteur résidentiel, les programmes « *Chauffe-eau efficace (volet location)* », « *Récupérateur de chaleur des eaux de douche* » et « *Chaudières à efficacité supérieure (volets achat et location)* » et, au secteur CI, le programme « *Chauffe-eau efficace (petit réservoir)* ».

[340] En audience, S.É./AQLPA signale que Gazifère n'inclut pas les dépenses du tronc commun lorsqu'elle évalue le test de neutralité tarifaire (TNT) global du PGEÉ. Le distributeur indique que ce test n'étant pas un indicateur décisionnel, il ne juge pas important d'inclure les dépenses du tronc commun dans son résultat.

[341] **La Régie considère que le TNT donne une indication de l'impact sur les tarifs du PGEÉ dans son ensemble. En conséquence, elle demande à Gazifère d'inclure les dépenses du tronc commun dans le calcul du TNT.**

[342] **La Régie prend acte de l'analyse de rentabilité du PGEÉ 2011, sous réserve de l'impact sur cette rentabilité des modifications demandées dans la présente décision.**

8.4 MÉCANISME INCITATIF AXÉ SUR LE PGEÉ

[343] En 2011, Gazifère souhaite introduire un mécanisme incitatif axé sur la performance de son PGEÉ. Le distributeur propose la mise en place d'une bonification comprenant une composante fixe liée à l'atteinte d'une cible et une composante variable liée au dépassement des bénéfices nets actualisés (BNA) du PGEÉ prévus en début d'année.

[344] Gazifère fait référence aux mécanismes incitatifs liés à l'efficacité énergétique en place chez cinq distributeurs de gaz naturel nord-américains :

- EGD (Ontario);
- FortisBC (Colombie-Britannique);
- Gaz Métro (Québec);
- CenterPoint Energy (Minnesota et Texas);
- Pacific Gas and Electric (Californie).

[345] En réponse à des demandes de la Régie, le distributeur indique qu'il ne dispose d'informations que sur les mécanismes incitatifs de trois des cinq distributeurs (Gaz Métro, EGD et FortisBC). Il n'explique toutefois pas comment les incitatifs à la performance en efficacité énergétique de ces trois distributeurs s'intègrent dans la bonification liée à leur performance globale[110].

[346] Le GRAME appuie la proposition de Gazifère. L'intervenant invoque l'équité avec Gaz Métro pour justifier sa position. Il précise toutefois que la bonification de Gaz Métro a été compensée partiellement par une modification du revenu plafond et indique que la comparaison des deux mécanismes est difficile[111].

[110] Pièce B-44, GI-41, document 1, pages 22 et 23.
[111] Pièce C-4-14, pages 7 à 12.

[347] L'UMQ appuie le principe d'un incitatif mais propose de réduire la portion fixe et de plafonner la bonification totale[112].

[348] L'ACEFO considère que Gazifère a intérêt à promouvoir l'efficacité énergétique en l'absence d'incitatif mais ne s'objecte pas au principe d'un tel incitatif. Elle propose des modifications au calcul de l'incitatif, une réduction de ce dernier et l'élimination du compte d'écart relatif au PGEÉ[113].

[349] La FCEI s'oppose à l'introduction d'un incitatif à la performance du PGEÉ. L'intervenante souligne que l'interprétation de Gazifère sur l'asymétrie de la bonification accordée à Gaz Métro dans le cadre de son mécanisme incitatif ne tient pas compte du fait que cette bonification a une contrepartie qui est la réduction du revenu plafond. L'intervenante soulève un doute sur la validité de l'analyse de Gazifère des mécanismes des autres distributeurs qu'elle cite en exemple[114].

[350] Gazifère est d'avis que l'amélioration de la performance du PGEÉ doit passer par la bonification des efforts qui y sont rattachés. En réponse à une demande de la Régie, Gazifère indique que les activités en efficacité énergétique occasionnent des investissements en ressources humaines pour lesquels elle n'est pas compensée. Ainsi, le distributeur n'inclut pas au tronc commun les coûts associés à l'implication des gestionnaires et du personnel de tous les secteurs d'activités de l'entreprise (ventes, réglementation, opérations, comptabilité, communication, etc.). Il invoque également le fait que le mandat de gestion et de développement du PGEÉ est, depuis 2006, confié principalement à ses employés plutôt qu'à une firme de consultants[115]. En audience, le distributeur explique que c'est par souci de simplicité qu'il ne comptabilise pas toutes les heures consacrées à l'efficacité énergétique par du personnel non attitré à ces activités[116].

[351] La Régie note que Gazifère est pleinement compensée pour les coûts associés à la mise en œuvre de son PGEÉ par un compte d'écart. De plus, les coûts du PGEÉ sont traités comme une exclusion dans le mécanisme incitatif, ce qui fait que le distributeur

112 Pièce C-6-17, pages 14 à 19.
113 Pièce C-1-32, pages 7 à 10.
114 Pièce C-3-25, pages 8 à 11.
115 Pièce B-44, GI-41, document 1, pages 23 et 24.
116 Pièce A-49-2, page 56.

n’encourt aucun risque à cet égard. Le distributeur indique vouloir maintenir ce compte en plus de l’incitatif qu’il propose[117].

[352] Gazifère soulève également l’élimination du compte d’écart volumétrique (CEV) comme élément pour justifier un incitatif à la performance. La Régie note, comme la FCEI, que le distributeur a reconnu, en Phase 1 du présent dossier, que ce compte n’est plus requis, compte tenu des faibles montants qui y ont été comptabilisés dans les dernières années[118].

[353] La Régie est d’avis que la comparaison avec le régime en vigueur chez Gaz Métro est inadéquate, puisque l’introduction de cette bonification chez cette dernière a été, pour l’essentiel, compensée par une diminution du revenu plafond, tel que souligné par la FCEI.

[354] **Compte tenu de ce qui précède, la Régie considère que l’introduction d’un incitatif à la performance du PGEÉ, au-delà de la bonification que le distributeur peut obtenir dans le cadre de son mécanisme incitatif, n’est pas justifiée. Elle refuse la proposition de Gazifère.**

8.5 COMPTE D’AIDE À LA SUBSTITUTION DES ÉNERGIES POLLUANTES (CASEP)

[355] Gazifère propose la mise en place d’un CASEP dans le secteur résidentiel. Le distributeur indique qu’un tel programme l’aidera à diminuer les émissions de gaz à effet de serre (GES) sur le territoire qu’elle dessert et permettra la densification du réseau actuel par l’ajout de clients.

[356] Le programme proposé offrirait une aide financière de 825 $ à des nouveaux clients souhaitant convertir au gaz naturel leur système de chauffage au mazout léger ou au propane. Pour l’année 2011, Gazifère prévoit 91 participants au programme, pour un budget total de 75 000 $[119]. Le distributeur indique, en réponse à une demande de la

[117] Pièce B-44, GI-41, document 1, page 25.
[118] Pièce A-26-1, pages 180 et 181.
[119] Pièce B-35, GI-37, document 1, page 27.

FCEI, que le nombre de conversions prévu en 2011, en l'absence d'un CASEP, serait de 57[120]. La mise en place d'un CASEP permettrait donc un gain de 34 conversions.

[357] Le GRAME recommande l'approbation du CASEP pour les mêmes motifs que le distributeur[121].

[358] S.É./AQLPA recommande également l'approbation du CASEP proposé par Gazifère, dans la mesure où le distributeur évalue le taux d'opportunisme du programme[122]. En audience, l'intervenant indique que l'analyse de la rentabilité du CASEP devrait tenir compte du taux d'opportunisme. Il précise que les 57 participants prévus pour 2011, si le CASEP n'est pas mis en place, peuvent être considérés comme des opportunistes[123].

[359] L'UMQ appuie l'introduction d'un CASEP, mais recommande que le budget proposé soit réduit à 50 000 $. L'intervenante propose que l'aide financière soit moins élevée pour les opportunistes. Elle n'indique toutefois pas comment le distributeur pourrait identifier cette catégorie de participants a priori[124].

[360] La FCEI conteste les hypothèses utilisées par le distributeur pour effectuer son analyse de rentabilité. L'intervenante soutient que la consommation prévue pour les nouveaux clients est trop élevée et que le distributeur devrait tenir compte des opportunistes dans son calcul. À partir d'hypothèses modifiées, la FCEI calcule que les périodes de retour sur l'investissement vont atteindre près de 10 ans pour le participant et plus de 50 ans pour le distributeur si le CASEP proposé est approuvé. L'intervenante recommande de refuser la proposition de Gazifère[125].

[361] La FCEI demande que l'ensemble du coût de 75 000 $ proposé par Gazifère pour le CASEP soit utilisé afin d'alléger le niveau d'interfinancement entre le tarif 2 et les autres tarifs du distributeur. Elle justifie sa demande en tenant pour acquis que la clientèle au tarif 2 du distributeur est en mesure d'absorber cette hausse de coût[126]. L'intervenante

[120] Pièce B-43, GI-44, document 1, page 37.
[121] Pièce C-4-14, pages 17 à 22.
[122] Pièce C-5-16, pages 3 à 7.
[123] Pièce A-49-2, page 149.
[124] Pièce C-6-17, pages 20 à 22.
[125] Pièce C-3-25, page 15.
[126] Pièce C-3-25, page 17.

reconnaît cependant qu'elle n'a pas évalué l'impact de sa demande sur le niveau d'interfinancement des autres tarifs de distribution du distributeur[127].

[362] La Régie est d'avis que toute proposition d'ajustement de l'interfinancement doit s'appuyer sur une réflexion plus globale quant à la stratégie tarifaire que Gazifère compte suivre. D'ailleurs, elle considère que toute question de cette nature n'a aucun lien propre avec le fait d'accepter ou non la proposition du CASEP du distributeur. La Régie juge donc qu'il n'est pas opportun de donner suite à la recommandation de la FCEI.

[363] Gazifère présente une analyse de la rentabilité du CASEP pour elle et pour les participants. Cette analyse est basée sur un coût total de conversion de 4 500 $ pour le participant et un coût de raccordement de 1 770 $ pour le distributeur.

[364] En audience, Gazifère explique ne pas avoir tenu compte des opportunistes dans son analyse du CASEP parce qu'il ne s'agit pas d'un programme d'efficacité énergétique et que cette notion, selon elle, ne s'applique qu'à ce type de programme. Le distributeur précise que Gaz Métro ne tient pas compte des opportunistes lorsqu'elle évalue la performance de son CASEP[128].

[365] En réponse à des questions de la Régie, le distributeur indique que le montant de 4 500 $ retenu comme coût de conversion est un coût moyen, basé sur des cas réels, qui inclut les équipements et leur installation. Le distributeur est incapable d'évaluer le surcoût entre l'installation d'un système au gaz naturel et les autres options qui s'offrent au client potentiel qui choisirait de remplacer son système de chauffage au mazout.

[366] Quant à ses prévisions de participation, le distributeur n'est pas en mesure de dire quelle est la proportion de participants qui remplacent leur appareil au mazout parce que celui-ci a atteint la fin de sa vie utile et la proportion de ceux qui remplacent un appareil en bon état pour réduire leur coût d'énergie ou pour réduire la quantité de GES émise[129].

[367] Le CASEP de Gaz Métro et celui proposé par Gazifère ne sont pas de même nature. Dans le premier cas, il s'agit d'un programme intégré dans le mécanisme incitatif du distributeur qui s'applique à toute la clientèle. Les montants utilisés sont déterminés au

[127] Pièce A-49-2, pages 104 et 105.
[128] Pièce A-49-2, pages 14 à 16.
[129] Pièce A-49-2, pages 51 à 53.

cas par cas en fonction de ce qui est requis pour amener le point mort tarifaire des coûts d'extension de réseau au même niveau que celui du plan de développement normal. Le CASEP proposé par Gazifère est plutôt similaire à un programme d'efficacité énergétique où une subvention est versée à tous les clients qui effectuent une conversion au gaz naturel.

[368] Dans sa cause tarifaire 2009[130], Gazifère avait jugé non pertinent d'introduire un CASEP. Le distributeur considérait la situation du gaz naturel plutôt favorable et jugeait déraisonnable d'imposer de nouveaux frais à la clientèle[131]. En réponse à une demande de la Régie dans le présent dossier, le distributeur reconnaît que, par rapport à la situation qui prévalait en 2008, le coût du gaz naturel est plus bas en 2010 et est en meilleure position concurrentielle par rapport à l'électricité[132]. En audience, il explique cependant que le nombre de conversions qu'il observe est en déclin depuis 2008 et qu'il se doit de réagir et innover[133].

[369] Compte tenu du modèle de CASEP proposé par Gazifère, la Régie considère qu'il doit être examiné de la même façon qu'un programme d'efficacité énergétique.

[370] Ainsi, l'analyse de rentabilité doit prendre en compte le taux d'opportunisme du programme. Dans la situation actuelle, en absence d'évaluation formelle, la Régie juge que la meilleure approximation pour ce taux est 64 %, soit le rapport entre les prévisions de conversions sans et avec CASEP (57/91). La Régie juge de plus qu'une telle intervention dans le marché doit se justifier sur la base du surcoût que le choix du gaz naturel impose au client par rapport à d'autres formes d'énergie.

[371] **Sur cette base, et compte tenu du taux élevé d'opportunisme anticipé, la Régie considère qu'il n'y a pas lieu d'accepter le programme proposé.**

[130] Dossier R-3665-2008.
[131] Décision D-2008-144, page 42.
[132] Pièce B-44, GI-41, document 1, pages 27 et 28.
[133] Pièce A-49-2, page 139.

8.6 SUIVI DE DÉCISIONS ANTÉRIEURES DE LA RÉGIE

[372] Conformément à une demande de la Régie[134], Gazifère dépose une mise à jour de son plan d'évaluation de ses programmes d'efficacité énergétique. En 2011, elle prévoit dépenser 5 000 $ pour des activités d'évaluation.

[373] Selon son calendrier d'évaluation déposé dans le dossier R-3692-2009, Gazifère prévoyait évaluer les programmes « *Appui aux initiatives – optimisation énergétique des bâtiments* » et « *Chaudière à efficacité intermédiaire (volets achat et location)* » du secteur CI. Ces deux évaluations n'ont pu être conduites, faute d'un nombre suffisant de participants et sont reportées à 2011.

[374] En 2010, Gazifère a procédé à l'évaluation de deux programmes, « *Trousse de produits économiseurs d'eau chaude* » et « *Chauffe-eau instantané* », dont elle dépose les résultats. Dans le cas du « *Chauffe-eau instantané* », il s'agit d'un suivi de la décision D-2009-151[135].

[375] À la suite de l'évaluation du projet-pilote « *Chauffe-eau instantané (volets achat et location)* », Gazifère propose le retrait de tous les volets de ce programme. Le surcoût élevé, les faibles économies unitaires et l'ampleur du taux d'opportunisme net constaté (44 %) amènent le distributeur à conclure que ce programme ne sera jamais rentable[136].

[376] S.É./AQLPA et ACEFO demandent le maintien du programme en attendant les résultats d'une évaluation d'un programme similaire que Gaz Métro doit réaliser dans la prochaine année. Les deux intervenants soulignent que le taux d'opportunisme utilisé actuellement par Gaz Métro est plus faible que celui mesuré par Gazifère. La Régie ne retient pas cette recommandation. Elle considère que, dans le contexte qui lui est propre, Gazifère a les compétences suffisantes pour réaliser des évaluations et qu'elle utilise des méthodes qui lui permettent d'avoir un portrait réaliste de la performance de ses programmes dans son marché.

[134] Décision D-2007-130, dossier R-3637-2007 Phase 2, pages 26 et 27.
[135] Dossier R-3692-2009, page 37.
[136] Pièce B-35, GI-37, document 1, page 15.

[377] L'évaluation du programme « *Trousse de produits économiseurs d'eau chaude* » amène une révision des cas types des différents volets de ce programme et l'introduction d'un taux d'opportunisme net de 30 % pour les volets offrant des produits gratuits.

[378] **La Régie prend acte du plan d'évaluation, des coûts s'y rattachant et des résultats des évaluations réalisées en 2010. Elle accepte le retrait du programme « *Chauffe-eau instantané* ».**

[379] Dans la décision D-2009-151, la Régie demandait à Gazifère d'inclure, dans son prochain sondage de satisfaction de la clientèle, des questions sur l'adoption des mesures d'efficacité énergétique visées par les programmes « *Trousse de produits économiseurs d'eau chaude* », « *Thermostat programmable* » et « *Chauffe-eau efficace (location)* » et de rapporter les résultats obtenus dans le présent dossier tarifaire[137].

[380] Pour ce qui est du programme « *Trousse de produits économiseurs d'eau chaude* », les résultats du sondage montrent que seulement 8,3 % des clients ont profité de l'offre gratuite de produits économiseurs d'eau chaude. Au moment du sondage, 33 % des participants n'avaient pas ou plus en place les produits offerts. Le sondage a également permis de constater que 21 % des clients avaient tout de même installé des produits économiseurs d'eau chaude sans avoir participé au programme[138]. Le distributeur mentionne également que 7 participants sur les 117 sondés (6 %) avaient augmenté la température de leur chauffe-eau après l'intervention de Gazifère pour la réduire. Il explique ne pas avoir intégré de taux d'effritement pour tenir compte de ce phénomène, compte tenu que le sondage montrait qu'un pourcentage plus élevé de participants avaient diminué la température de leur chauffe-eau.

[381] L'ACEFO conteste la justification de Gazifère de ne pas tenir compte des participants qui augmentent la température de leur appareil et recommande qu'un taux d'effritement de 6 % soit intégré aux résultats du volet réduction de la température du chauffe-eau.

[382] À partir de ces résultats, Gazifère évalue le potentiel résiduel théorique de ce programme à plus de 30 ans. Le distributeur précise, à la suite d'une demande de la

[137] Dossier R-3692-2009, page 38.
[138] Pièce B-35, GI-37, document 1, page 14.

Régie, que pour le volet réduction de la température du chauffe-eau, ce potentiel théorique est de 7,5 ans.

[383] En audience, Gazifère indique que lors de l'installation d'un chauffe-eau efficace en location, elle réduit systématiquement la température du chauffe-eau installé[139]. Compte tenu du nombre d'appareils efficaces que Gazifère a installés depuis la mise en place du programme « *chauffe-eau efficace* » (au 31 décembre 2008, il y avait eu 27 788 participants à ce programme[140]), il semble que le potentiel résiduel associé à la réduction de la température du chauffe-eau ne comprenne que des nouveaux clients et des participants qui ont augmenté la température de leur chauffe-eau après que celle-ci ait été ajustée à la baisse.

[384] **La Régie prend acte des nouveaux cas types du programme « *Trousse de produits économiseurs d'eau chaude* ». Elle constate qu'il reste encore un potentiel significatif dans ce programme, sauf pour ce qui est du volet réduction de la température du chauffe-eau. Dans ce dernier cas, elle demande à Gazifère de ne comptabiliser des réductions de consommation que dans les cas où son intervention résulte en une réduction effective de la température de l'appareil. Par ailleurs, la Régie demande à Gazifère d'intégrer un taux d'effritement dans ses prévisions pour tous les volets du programme.**

[385] Dans le cas du programme « *Thermostat programmable* », le sondage de Gazifère montre qu'une forte proportion des clients (84 %) a installé un thermostat programmable. Parmi ces clients, seulement 16,5 % ont profité de l'offre de Gazifère et 22 % n'avaient pas programmé leur thermostat au cours de la dernière saison froide[141].

[386] Le distributeur présente les résultats d'un sondage réalisé en 2008 sur les habitudes de programmation. Parmi les répondants, 14,1 % n'avaient pas programmé leur thermostat au cours de la dernière saison ou le maintenaient à une température constante[142], ce qui semble corroborer les résultats du sondage 2010. Les chiffres présentés par le distributeur montrent qu'il reste moins de 2 000 clients qui n'ont pas de thermostat programmable.

139 Pièce A-49-2, page 48.
140 Pièce A-50.
141 Pièce B-35, GI-37, document 1, page 14.
142 Pièce B-44, GI-41, document 1, page 16.

[387] En audience, Gazifère indique que le programme permet qu'un participant remplace un thermostat programmable par un autre thermostat programmable. Le distributeur justifie cette façon de faire en expliquant que, lorsque son thermostat programmable est en fin de vie utile, un client peut faire le choix de le remplacer par un modèle conventionnel et que le programme l'incite à installer un modèle programmable.

[388] Le distributeur précise en audience que ses prévisions de participation au programme pour 2011 incluent principalement des nouveaux clients et ne sont pas seulement basées sur les 2 000 clients ciblés dans le potentiel résiduel.

[389] Dans la décision D-2008-144[143], la Régie avait accepté que le volet « *nouvelle construction* » du programme « *Thermostat programmable* » soit abandonné. Ainsi, la Régie comprend que les nouveaux clients que le distributeur inclut dans sa prévision de participation pour 2011 devraient être des clients qui utilisent une autre forme d'énergie et qui choisissent de devenir clients de Gazifère. Il s'agit donc de clients qui convertissent leur système de chauffage au gaz naturel. Puisque Gazifère prévoit 57 conversions en 2011[144], la Régie considère élevée la prévision de 471 participants (brut) pour l'ensemble des volets du programme.

[390] **Même si le potentiel résiduel du programme « *Thermostat programmable* » est faible, la Régie juge qu'il est pertinent de le poursuivre. Elle demande toutefois au distributeur de limiter la participation à ce programme aux clients qui remplacent un thermostat conventionnel par un thermostat programmable de façon à ne comptabiliser que des réductions effectives de consommation. Elle lui demande également d'intégrer, dans ses résultats, un taux d'effritement de 15 % et de revoir ses prévisions de participation en tenant compte de la présente décision.**

[391] Gazifère évalue que le potentiel résiduel du programme « *Chauffe-eau efficace (location)* » pourrait permettre de le maintenir encore 2,5 années. Le distributeur inclut dans le potentiel résiduel les clients ayant participé au programme et dont l'appareil doit être remplacé parce qu'il arrive en fin de vie utile.

[392] Selon les données de Gazifère, ce programme a réussi à atteindre la quasi-totalité des clients qui louent un chauffe-eau. Au 31 décembre 2008, le distributeur avait installé

[143] Dossier R-3665-2008, page 38.
[144] Pièce B-35, GI-37, document 1, page 14.

26 788 chauffe-eau efficaces[145]. En ajoutant à ce nombre les données de participation au programme pour 2009[146] et pour les six premiers mois de 2010[147], la Régie constate que le nombre de chauffe-eau efficaces installés dépasse le nombre de clients louant un tel appareil.

[393] En audience, le distributeur indique qu'il n'est pas en mesure de dire s'il reste encore des clients louant un chauffe-eau conventionnel. Il précise qu'il est possible que des chauffe-eau installés avant la mise en place du programme ne soient pas des appareils efficaces[148]. Compte tenu que Gazifère estime la durée de vie moyenne d'un chauffe-eau à 8 ans[149] et que le programme a été approuvé en 2000, la Régie estime que le nombre de chauffe-eau conventionnels encore en usage doit être faible.

[394] **La Régie considère que Gazifère a atteint la totalité du potentiel que ce programme offrait. Le distributeur est parvenu, grâce à ses efforts depuis plus de 10 ans, à remplacer la quasi-totalité des chauffe-eau de son parc de location par des appareils efficaces. Compte tenu que le programme remplace désormais des chauffe-eau efficaces, la Régie considère qu'il n'apporte plus de réductions nettes de consommation réelles. Elle demande donc à Gazifère de ne plus comptabiliser de réductions de consommation pour l'installation de chauffe-eau efficaces dans le cadre de son PGEÉ.**

8.7 MODIFICATIONS AUX PROGRAMMES

[395] Gazifère propose l'introduction d'un programme de subvention à l'installation de récupérateurs de chaleur des eaux de douche s'adressant aux coopératives d'habitation et aux organismes à vocation sociocommunautaire.

[396] Les données du cas type du programme proviennent d'un programme similaire du FEÉ de Gaz Métro. Le participant type de ce programme consomme au total 112 000 m^3/an[150].

145 Pièce A-50.
146 Pièce B-4, GI-21, document 1.1.
147 Pièce B-43, GI-37, document 2.
148 Pièce A-49-2, page 47.
149 Pièce B-35, GI-37, document 1, page 50.
150 Pièce B-35, GI-37, document 1, page 50.

[397] En réponse à un engagement pris en audience, Gazifère donne la consommation totale moyenne, au cours de l'année 2009, des 21 clients potentiels pour ce nouveau programme. La Régie constate que la consommation moyenne des organismes à vocation sociocommunautaire a été de 12 826 m^3 et que celle des coopératives d'habitation a été de 61 435 m^3. Un seul des 21 clients a consommé plus de 100 000 m^3 au cours de 2009[151].

[398] **La Régie accepte la mise en place du programme et demande à Gazifère de revoir le cas type et les prévisions volumétriques en fonction des consommations réelles de la clientèle visée. Elle lui demande également de réviser le calcul du TCTR de ce programme avec le cas type révisé, au plus tard le 10 décembre 2010 à 12 h.**

9. CHARGES LIÉES AU COÛT DU GAZ NATUREL

[399] Conformément à la demande de la Régie[152], Gazifère indique l'impact des volumes de ventes prévus sur son coût du gaz naturel selon le Tarif 200 d'EGD[153]. Pour l'année tarifaire 2011, cet impact se traduit par une diminution de 87 500 $ des charges liées au coût du gaz naturel.

[400] **La Régie est satisfaite des informations fournies et prend acte de la diminution de 87 500 $ des charges liées au coût du gaz naturel pour l'année tarifaire 2011.**

10. SUIVI DES DÉCISIONS ANTÉRIEURES

[401] Conformément à la décision de la Régie, Gazifère fait état des écritures comptables requises afin que les soldes des comptes de frais reportés (CFR) de redressement soient ramenés à zéro au 31 décembre 2010[154]. La Régie s'en déclare satisfaite.

[151] Pièce B-54, GI-41, document 3.
[152] Décision D-2007-03, dossier R-3587-2005 Phase 2.
[153] Pièce B-43, GI-40, document 1.
[154] Pièce B-35, GI-34, document 1, réponse R.10.

11. AJUSTEMENT FINAL DES TARIFS 2011

[402] **La Régie demande à Gazifère de modifier et de déposer, au plus tard le 10 décembre 2010 à 12 h, l'ensemble des pièces au dossier nécessaires à l'établissement des tarifs finaux de l'année tarifaire 2011, en tenant compte des modifications découlant de la présente décision.**

[403] **Pour l'ensemble de ces motifs,**

La Régie de l'énergie :

ACCUEILLE en partie la demande du 4 mars 2010 et la demande amendée du 30 août 2010 de Gazifère;

MAINTIENT la présente structure de capital de Gazifère, composée de 40 % de capitaux propres et de 60 % de capitaux empruntés;

FIXE le taux de rendement sur l'avoir de l'actionnaire de Gazifère à 9,10 % pour l'année tarifaire 2011;

ÉTABLIT le calcul du taux de rendement sur l'avoir de l'actionnaire de Gazifère pour l'année 2012 et les années subséquentes, selon la formule d'ajustement automatique présentée à l'annexe 1;

APPROUVE le plan d'approvisionnement de Gazifère pour l'exercice 2011, sous réserve de sa décision quant au niveau de la prévision de la demande des clients au tarif 9 du distributeur;

MODIFIE les tarifs de Gazifère, à compter du 1er janvier 2011, de façon à ce qu'ils puissent générer les revenus de distribution établis à la suite de l'application de la formule approuvée par la Régie dans le cadre de la Phase 1 du présent dossier;

APPROUVE les paramètres utilisés et le calcul fait par Gazifère pour établir les revenus requis de distribution pour l'année témoin 2011, sous réserve de la mise à jour du taux de rendement sur l’avoir de l’actionnaire selon la présente décision de la Régie portant sur la Phase 2 et sujets aux modifications à apporter à l’ensemble des éléments découlant de la présente décision;

APPROUVE les charges réglementaires, les charges liées au PGEÉ et les charges liées à la quote-part versée à l’Agence de l’efficacité énergétique, prévues par Gazifère pour l’année témoin 2011, telles que présentées à la pièce B-41, GI-35, document 2.3, et **AUTORISE** Gazifère à inclure ces montants dans l’établissement du revenu requis de l’année témoin 2011 à titre d’exclusion;

APPROUVE les soldes des comptes différés relatifs aux charges réglementaires, aux programmes d’efficacité énergétique et à la quote-part versée à l’Agence de l’efficacité énergétique (compte d’écart 2009), tels que présentés à la pièce B-41, GI-35, document 2.3, et **AUTORISE** Gazifère à inclure les soldes de ces comptes différés dans l’établissement du revenu requis de l’année témoin 2011 à titre d’exclusion;

PREND ACTE des résultats et des dépenses relatives au PGEÉ pour les six premiers mois de 2010, sous réserve des modifications découlant de la présente décision, et **DEMANDE** à Gazifère de déposer les résultats corrigés lors du dépôt des pièces modifiées pour l’établissement des tarifs finaux pour l’année tarifaire 2011, **soit au plus tard le 10 décembre 2010 à 12 h**;

APPROUVE le PGEÉ 2011, sous réserve des modifications découlant de la présente décision et **DEMANDE** à Gazifère de déposer, **au plus tard le 10 décembre 2010 à 12 h,** les budgets monétaire et volumétrique du PGEÉ 2011 intégrant ces modifications;

REJETTE la proposition de Gazifère d’introduire un incitatif à la performance du PGEÉ;

REJETTE la proposition de Gazifère de mettre en place un CASEP;

AUTORISE les projets d’extension et de modification du réseau de Gazifère détaillés à la pièce B-35, GI-34, document 2, à l’exclusion de tout projet dont le coût est égal ou supérieur au seuil de 450 000 $ énoncé dans le *Règlement sur les conditions et les cas requérant une autorisation de la Régie de l'énergie*[155] et qui n'a pas déjà reçu une autorisation préalable de la Régie en vertu de l'article 73 de la Loi et dudit règlement;

APPROUVE un taux de gaz naturel perdu de 0,91 % pour l'année témoin 2011;

DEMANDE à Gazifère de modifier et de déposer, **au plus tard le 10 décembre 2010 à 12 h**, l'ensemble des pièces au dossier nécessaires à l'établissement des tarifs finaux de l'année tarifaire 2011, en tenant compte des modifications découlant de la présente décision;

ORDONNE à Gazifère de se conformer à l'ensemble des autres éléments décisionnels contenus dans la présente décision.

Louise Rozon
Régisseur

Richard Carrier
Régisseur

Lise Duquette
Régisseur

[155] (2001) 133 G.O. II, 6165.

Représentants :

- Association coopérative d'économie familiale de l'Outaouais (ACEFO) représentée par M^{e} Stéphanie Lussier;
- Association des consommateurs industriels de gaz (ACIG) représentée par M^{e} Guy Sarault et M^{e} Nicolas Plourde;
- Fédération canadienne de l'entreprise indépendante (section Québec) (FCEI) représentée par M^{e} André Turmel et M^{e} Pierre-Olivier Charlebois;
- Gazifère Inc. (Gazifère) représentée par M^{e} Louise Tremblay;
- Groupe de recherche appliquée en macroécologie (GRAME) représenté par M^{e} Geneviève Paquet;
- Stratégies énergétiques et Association québécoise de lutte contre la pollution atmosphérique (S.É./AQLPA) représenté par M^{e} Dominique Neuman;
- Union des municipalités du Québec (UMQ) représentée par M^{e} Steve Cadrin et M^{e} Martine Burelle.

ANNEXE 1

Formule d'ajustement automatique du taux de rendement sur l'avoir de l'actionnaire de Gazifère Inc.

Annexe 1 (2 pages)

L. R. __________

R. C. __________

L. D. __________

ANNEXE 1

FORMULE D’AJUSTEMENT AUTOMATIQUE DU TAUX DE RENDEMENT SUR L’AVOIR DE L’ACTIONNAIRE DE GAZIFÈRE INC. POUR L’ANNÉE 2012 ET LES ANNÉES SUBSÉQUENTES

Taux de rendement sur l’avoir de l’actionnaire pour l’année témoin t = 9,10 % + 0,75 * ($POCL_t$ – 4,25%) + 0,5 * ($ECSR_t$ – 1,5%)

où :

$POCL_t$ = Prévision du taux de rendement des obligations du Canada de long terme pour l’année témoin t.

$ECSR_t$ = Écart de crédit des obligations de long terme des sociétés réglementées canadiennes de cote de crédit A par rapport aux obligations du Canada de long terme pour l’année témoin t.

Le facteur $POCL_t$ est calculé comme suit :

$$POCL_t = \left[\frac{PO_{10}C_{jan,t} + PO_{10}C_{oct,t}}{2}\right] + \left[\frac{\sum_i \left(O_{30}C_{i,t-1} - O_{10}C_{i,t-1}\right)}{I}\right]$$

où :

$PO_{10}C_{jan,t}$ = Prévision du taux de rendement des obligations 10 ans du gouvernement du Canada à la fin du mois de janvier de l’année témoin t, telle qu’elle apparaît dans la publication du mois d’octobre de l’année tarifaire t-1 du Consensus Forecasts.

$PO_{10}C_{oct,t}$ = Prévision du taux de rendement des obligations 10 ans du gouvernement du Canada à la fin du mois d’octobre de l’année témoin t, telle qu’elle apparaît dans la publication du mois d’octobre de l’année tarifaire t-1 du Consensus Forecasts.

$O_{30}C_{i,t-1}$ = Taux de rendement des obligations 30 ans du gouvernement du Canada à la clôture de chaque journée ouvrable i du mois de septembre de l’année tarifaire t-1 tel que publiés par la Banque du Canada (Cansim Series V39056).

$O_{10}C_{i,t-1}$ = Taux de rendement des obligations 10 ans du gouvernement du Canada à la clôture de chaque journée ouvrable i du mois de septembre de l'année tarifaire t-1 tel que publiés par la Banque du Canada (Cansim Series V39055).

I = Nombre de journées ouvrables dans le mois de septembre de l'année tarifaire t-1 pour lesquelles les taux de rendement des obligations du gouvernement du Canada et les taux de rendement des obligations 30 ans des sociétés réglementées canadiennes de cote de crédit A sont publiés.

Le facteur $ECSR_t$ correspond à la moyenne des écarts de rendement quotidiens entre les obligations 30 ans des sociétés réglementées canadiennes de cote de crédit A et les obligations 30 ans du gouvernement du Canada, constatés chaque journée ouvrable i du mois de septembre de l'année tarifaire t-1. Le facteur $ECSR_t$ est calculé comme suit :

$$ECSR_t = \frac{\sum_i \left(O_{30}SR_{i,t-1} - O_{30}C_{i,t-1}\right)}{I}$$

où :

$O_{30}SR_{i,t-1}$ = Moyenne quotidienne des taux de rendement des obligations 30 ans des sociétés réglementées canadiennes de cote de crédit A à la clôture de chaque journée ouvrable i du mois de septembre de l'année tarifaire t-1, telle qu'elle apparaît à l'indice C29530Y publié par Bloomberg.

$O_{30}C_{i,t-1}$ = Taux de rendement des obligations 30 ans du gouvernement du Canada à la clôture de chaque journée ouvrable i du mois de septembre de l'année tarifaire t-1 tel que publiés par la Banque du Canada (Cansim Series V39056).

I = Nombre de journées ouvrables dans le mois de septembre de l'année tarifaire t-1 pour lesquelles les taux de rendement des obligations du gouvernement du Canada et les taux de rendement des obligations 30 ans des sociétés réglementées canadiennes de cote de crédit A sont publiés.

D É C I S I O N

QUÉBEC **RÉGIE DE L'ÉNERGIE**

D-2011-182	R-3752-2011 Phase 2	25 novembre 2011

PRÉSENTS :

Gilles Boulianne
Marc Turgeon
Jean-François Viau
Régisseurs

Société en commandite Gaz Métro
Demanderesse

et

Intervenants dont les noms apparaissent ci-après

Décision

Demande de modifier les tarifs de Société en commandite Gaz Métro à compter du 1er octobre 2011

Intervenants :

- Association des consommateurs industriels de gaz (ACIG);
- Fédération canadienne de l'entreprise indépendante (section Québec) (FCEI);
- Groupe de recherche appliquée en macroécologie (GRAME);
- Option consommateurs (OC);
- Regroupement des organismes environnementaux en énergie (ROEÉ);
- Regroupement national des conseils régionaux de l'environnement du Québec (RNCREQ);
- Stratégies énergétiques et Association québécoise de lutte contre la pollution atmosphérique (S.É./AQLPA);
- TransCanada Energy Ltd (TCE);
- Union des consommateurs (UC);
- Union des municipalités du Québec (UMQ).

TABLE DES MATIÈRES

1. INTRODUCTION

[1] Le 10 janvier 2011, Société en commandite Gaz Métro (Gaz Métro ou le distributeur) dépose à la Régie de l’énergie (la Régie) une demande de modification de ses tarifs et de certaines conditions de service à compter du 1er octobre 2011, qu’elle propose de traiter en deux phases. La demande est amendée à quatre reprises, soit les 26 avril, 6 mai, 9 juin et 31 août 2011.

[2] La phase 1 porte sur la mise en place de mesures liées à l’implantation de la « Solution intégrée » à la suite de son approbation par la Régie dans sa décision D-2010-144[1]. La « Solution intégrée » vise l’abolition du tarif modulaire (D_M), l’ouverture du tarif à débit stable (D_3) et le transfert des clients du tarif D_M vers les tarifs D_1 et D_3.

[3] La phase 2, quant à elle, porte sur les autres demandes, incluant celles soumises au processus d’entente négociée (PEN) prévu au mécanisme incitatif à l’amélioration de la performance (le Mécanisme) en vigueur.

[4] Pour la phase 2 du dossier, les intéressés suivants obtiennent le statut d’intervenant : l’ACIG, la FCEI, le GRAME, OC, le RNCREQ, le ROEÉ, S.É./AQLPA, TCE, l’UC et l’UMQ.

[5] Le 30 mars 2011, la Régie rend la décision D-2011-035 dans le cadre de la phase 1 du dossier dans laquelle elle se prononce, entre autres, sur la « Solution intégrée ».

[6] L’audience de la phase 2 du dossier s’est déroulée sur une période de 11 jours, entre les 7 et 23 septembre 2011.

[7] Le 30 septembre 2011, la Régie rend la décision D-2011-153 dans laquelle elle maintient, provisoirement, à compter du 1er octobre 2011, l’application des *Conditions de service et Tarif* actuellement en vigueur. Dans cette même décision, elle se prononce également sur les indices de prix utilisés dans les transactions de gaz naturel ainsi que sur le Programme de produits financiers dérivés.

[1] Dossier R-3720-2010 Phase 2.

[8] Le 28 octobre 2011, la Régie rend la décision D-2011-164 dans laquelle elle se prononce sur la fonctionnalisation des coûts d'équilibrage et ses conséquences tarifaires.

[9] Le 11 novembre 2011, la Régie demande à Gaz Métro de lui soumettre ses commentaires relativement aux notes du réviseur quant à la version anglaise du texte des *Conditions de service et Tarif*. Gaz Métro soumet ses commentaires le 17 novembre 2011.

[10] Dans la présente décision, la Régie se prononce sur les modifications tarifaires demandées dans le cadre de la phase 2.

2. CONCLUSIONS RECHERCHÉES

[11] Les conclusions recherchées par Gaz Métro en phase 2[2] sont :

« ***À L'ÉGARD DE LA PREUVE ISSUE DU PROCESSUS D'ENTENTE NÉGOCIÉE***

> ***RECONDUIRE*** *jusqu'au 30 septembre 2013, le programme de flexibilité tarifaire mazout pour les clients* D_1 *et* D_3*;*
>
> ***APPROUVER*** *l'entente intervenue entre les membres du Groupe de travail ainsi que toutes les pièces s'y rapportant;*
>
> ***APPROUVER*** *les budgets du PGEÉ 2011-2012 de Gaz Métro;*
>
> ***APPROUVER*** *le nouveau projet pilote du PGEÉ (PE123 Combo à condensation);*
>
> ***APPROUVER*** *les modifications proposées aux programmes existants du PGEÉ de Gaz Métro, au taux d'actualisation utilisé pour les fins des calculs des tests de rentabilité, et au calcul du test du participant (TP);*

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2 Pièce B-0229.

***APPROUVER**, pour l'exercice financier 2012, les volumes totaux pouvant être protégés en vertu du "Programme de produits financiers dérivés", ainsi que du plafond applicable aux contrats d'échange à prix fixes, avant le 1er octobre 2011;*

***MODIFIER**, à compter du 1er octobre 2011, les tarifs de Gaz Métro de façon à ce qu'ils génèrent les revenus requis s'élevant à environ à 949 782 000 $, de façon à permettre à Gaz Métro de récupérer l'ensemble de ses coûts;*

<u>À L'ÉGARD DU PLAN D'APROVISIONNEMENT 2011-2012, DU SUIVI 5 DANS LA DÉCISION D-2011-048 ET DE L'ACTIVITÉ GNL</u>

***APPROUVER** le plan d'approvisionnement 2011-2012;*

***APPROUVER** des revenus projetés de 58 000 $ pour les transactions opérationnelles et de 5 900 000 $ pour les transactions financières;*

***DÉCLARER** que la justification quant aux quantités et aux modalités de renouvellement des contrats d'entreposage répond au suivi requis;*

***APPROUVER** des coûts d'utilisation de l'usine LSR de 179 000 $ pour l'année 2012;*

***APPROUVER** la méthode d'établissement des coûts liés à la fourniture, la compression, le transport, l'équilibrage, la distribution et le Fonds vert plus amplement décrite à la section 4 de la pièce Gaz Métro-4, Document 3;*

***APPROUVER** un coût de maintien de la fiabilité de 100 000 $ pour l'année 2012;*

ALTERNATIVEMENT

***APPROUVER** l'alternative proposée par Gaz Métro à l'égard du coût de maintien de la fiabilité qui consiste à remplacer la facturation de ce coût par un engagement de Gaz Métro Solutions Transport à payer ce coût;*

<u>À L'ÉGARD DU TAUX DE RENDEMENT, DE LA STRUCTURE DE CAPITAL ET DU COÛT EN CAPITAL</u>

***APPROUVER** une structure de capital avec 42,5% d'avoir ordinaire, 3,5% d'avoir privilégié et 54% de dette;*

***APPROUVER** un taux de rendement de 9,8% sur l'avoir ordinaire;*

***APPROUVER** une formule d'ajustement automatique pour 3 ans en utilisant un coefficient d'élasticité de 50% et incluant une variable afin de tenir compte des écarts de crédit des compagnies réglementées;*

***APPROUVER** un coût en capital moyen de 8,01%;*

***APPROUVER** un coût en capital prospectif de 6,87%;*

À L'ÉGARD DE LA STRATÉGIE TARIFAIRE ET DU SUIVI 3 DANS LA DÉCISION D-2011-048

***APPROUVER** la stratégie tarifaire et les grilles tarifaires en découlant pour les tarifs D_1, D_3, D_4 et D_5;*

***APPROUVER** les prix applicables au service de transport;*

***APPROUVER** les prix et les taux applicables au service d'équilibrage;*

***DÉCLARER** que la démonstration quantitative de l'allocation du coût de service répond au suivi requis;*

***PRENDRE ACTE** des pistes de réflexions et ajustements proposés en lien avec l'étude de la méthode d'allocation des coûts;*

***APPROUVER** la réalisation d'une étude d'allocation des coûts aux deux ans applicable dès la cause tarifaire 2013;*

***DÉCLARER** que l'examen des liens entre les résultats de l'étude de répartition des coûts et les structures tarifaires existantes pour le tarif de distribution répond au suivi requis;*

***PRENDRE ACTE** de la vision tarifaire proposée par Gaz Métro;*

***DÉCLARER** que Gaz Métro a soumis diverses pistes d'amélioration et répond donc au suivi requis;*

À L'ÉGARD DU TEXTE DES* CONDITIONS DE SERVICE ET TARIF *ET DES SUIVIS 4 ET 9 À 12 DANS LA DÉCISION D-2011-048

***APPROUVER** les frais de base applicables au tarif de distribution D_1 à compter du 1^{er} octobre 2011;*

***APPROUVER** la définition de "coefficient d'utilisation" proposée;*

***ABROGER** l'article 16.3 "Service de distribution DM : Modulaire" ainsi que toute référence au tarif D_M aux articles 4.5.1, 4.10, 5.3.2, 13.1.3.1, 13.2.1, 13.2.3.1, 13.2.3.1.2, 14.1.2.3, 14.1.3.1 et 18.2.2;*

***APPROUVER** les modifications proposées au tableau de l'article 16.2.4.2 "Supplément pour service de pointe – Autres clients";*

***APPROUVER** la modification proposée à l'article 16.3 quant à l'application du service de distribution D_3;*

***APPROUVER** la modification proposée à l'article 16.3.4 "Prolongation de contrat";*

***ABROGER** les dispositions transitoires 18.1.7, 18.1.8, 18.1.13 et 18.1.15;*

***APPROUVER** les modifications proposées aux dispositions transitoires 18.2.8 et 18.2.10;*

***APPROUVER** la modification proposée au calcul du prix maximum au service d'équilibrage;*

***APPROUVER** la modification proposée au tableau de l'article 14.1.2.3 "Prix moyen";*

***APPROUVER** l'ajout d'une disposition transitoire à l'article 18.2.6, "Calcul du prix d'équilibrage";*

***APPROUVER** la modification proposée à l'article 18.2.2 "Retrait progressif des services de transport et d'équilibrage du distributeur";*

***APPROUVER** la modification aux noms des tarifs de distribution en vue de leur mise en vigueur au 1er octobre 2012;*

***APPROUVER** le texte des* Conditions de service et Tarif *tant dans sa version française qu'anglaise;*

<u>En lien avec les suivis requis par la décision D-2010-100</u> :

***DÉCLARER** que l'évaluation de Gaz Métro quant à l'emploi du mot "contrat" répond au suivi requis;*

***APPROUVER** les modifications proposées aux articles 4.5.1 et 16.1.1 ainsi qu'au 2e alinéa de l'article 18.2.2;*

***DÉCLARER** que la justification formulée par Gaz Métro quant à l'application du mot "jour" répond au suivi requis;*

***APPROUVER** la modification à la définition du mot "jour";*

***DÉCLARER** que la réponse formulée par Gaz Métro quant à l'article 4.3.3 répond au suivi requis;*

***APPROUVER** la modification proposée à l'article 4.3.3 "Frais pour branchement non standard";*

***APPROUVER** les définitions proposées pour les termes "point de raccordement" et "branchement";*

***APPROUVER** les modifications proposées aux articles 2.1 et 5.1.1;*

***APPROUVER** la modification proposée à l'article 6.1.1 "Volume de gaz naturel facturé";*

***APPROUVER** la définition proposée pour le terme "point de livraison convenu";*

En lien avec le suivi requis par la décision D-2010-144 **:**

DÉCLARER *que la réponse de Gaz Métro quant à la nécessité d'une utilisation du service de distribution pour qu'un contrat présumé intervienne entre l'occupant d'un local et le distributeur répond au suivi requis;*

En lien avec les suivis requis par la décision D-2011-016 **:**

DÉCLARER *que la réponse formulée par Gaz Métro quant à l'emploi des termes "rentable", "rentabilisation" et "rentabiliser" répond au suivi requis;*

APPROUVER *la modification à la version anglaise de l'article 4.4.2;*

APPROUVER *la modification à la version anglaise de l'article 6.1.1;*

APPROUVER *l'utilisation du terme "connection" à la version anglaise des articles 4.3.2 et 4.3.3;*

En lien avec les suivis requis par la décision D-2011-035 **:**

APPROUVER *le remplacement du mot "Stable" par l'expression "Stable Load" dans la version anglaise des* Conditions de service et Tarif*;*

APPROUVER *la modification apportée à la version anglaise visant à remplacer le terme "transitory" par "transitional" à l'ensemble des* Conditions de service et Tarif*;*

Autres révisions d'articles des* Conditions de service et Tarif*:

APPROUVER *les modifications proposées à la section 4 de la pièce Gaz Métro-14, Document 1;*

À l'ÉGARD DE LA MISE À JOUR DE LA STRATÉGIE DE GESTION DES ACTIFS ET SUIVI 7 DANS LA DÉCISION D-2011-048

DÉCLARER *que la mise à jour de la Stratégie de gestion des actifs, pièce Gaz Métro-11, Document 1, répond au suivi requis;*

À L'ÉGARD DU FEÉ ET DU SUIVI 2 DANS LA DÉCISION D-2011-048

***AUTORISER** l'utilisation des sommes imputés au Fonds en efficacité énergétique ("FEÉ") conformément au plan d'action du FEÉ;*

***DÉCLARER** que le rapport d'avancement relatif au plan d'action en vue de la dissolution du FEÉ répond aux suivis requis;*

À L'ÉGARD DU SUIVI 13 – ALTERNATIVE POUR L'ÉVALUATION QUANTITATIVE DES ÉCONOMIES D'ÉNERGIE POUR LE PROGRAMME PEE-208 ENCOURAGEMENT À L'IMPLANTATION – MARCHÉ D'AFFAIRES

***DÉCLARER** que l'alternative retenue par Gaz Métro permettant l'évaluation quantitative des économies d'énergie pour le programme PEE-208 Encouragement à l'implantation – Marché d'affaires répond au suivi requis;*

***APPROUVER** l'alternative proposée par Gaz Métro permettant l'évaluation quantitative des économies d'énergie pour le programme PEE-208 Encouragement à l'implantation – Marché d'affaires;*

***APPROUVER** l'échéancier pour la mise en place de l'alternative décrite à la pièce Gaz Métro-9, Document 5;*

***APPROUVER** un budget global de 351 925 $ pour la réalisation du projet, dont 113 415 $ pour l'année 2011-2012;*

À L'ÉGARD DU SUIVI 6 DANS LA DÉCISION D-2011-048 - PROPOSITIONS RELATIVES AU NOMBRE DE JOURS D'INTERRUPTION, AUX PRINCIPES D'ÉTABLISSEMENT DU TARIF D'ÉQUILIBRAGE POUR LA CLIENTÈLE INTERRUPTIBLE ET AU TARIF D'ÉQUILIBRAGE POUR LES CLIENTS EN GAZ D'APPOINT CONCURRENCE

***APPROUVER** l'abolition de la clause de compensation pour les 10 jours supplémentaires d'interruption;*

***APPROUVER** la modification à la méthode de fonctionnalisation des coûts de transport en considérant, au service de transport, les coûts reliés aux capacités de* *transport requises pour répondre à la moyenne annuelle de la demande projetée (après interruption);*

***APPROUVER** la modification à la méthode de fonctionnalisation des coûts reliés aux achats de gaz naturel à Dawn selon l'option 2;*

***PRENDRE ACTE** du fait qu'aucune modification à la formule du calcul du prix d'équilibrage pour les clients interruptibles n'est proposée dans le présent dossier;*

***APPROUVER** le maintien du prix minimum d'équilibrage à -1,561 ¢/m³ tel qu'établi dans le dossier R-3720-2010;*

***APPROUVER** l'établissement du prix d'équilibrage pour les clients GAC à la moyenne entre 0,000 ¢/m³ et le prix moyen du tarif D_4 mis à jour à chaque dossier tarifaire pour fins d'évaluation des revenus d'équilibrage inclus dans les revenus totaux facturés aux clients en service de GAC;*

À L'ÉGARD DES TAUX D'AMORTISSEMENT ET DU SUIVI 1 DANS LA DÉCISION D-2011-048

***APPROUVER** l'utilisation de la méthode ELG plutôt que la méthode ASL;*

***APPROUVER** la modification des taux d'amortissement applicables à certaines catégories d'actifs, tel que plus amplement explicité à l'annexe B de la pièce Gaz Métro-6, Document 8;*

***APPROUVER** la création des nouvelles catégories d'immobilisation décrites à l'annexe C de la pièce Gaz Métro-6, Document 8, ainsi que les taux d'amortissement afférents;*

***APPROUVER** la modification des taux d'amortissement applicables à certaines catégories d'immobilisations déjà existantes, tel que plus amplement explicité à l'annexe C de la pièce Gaz Métro-6, Document 8;*

***DÉCLARER** que le résultat de la validation de la vie utile des actifs touchés par le projet Senneville répond au suivi requis;*

À L'ÉGARD DU SUIVI 8 DANS LA DÉCISION D-2011-048 – RAPPORT D'ÉVALUATION DU PROGRAMME DE RABAIS À LA CONSOMMATION ("PRC") ET DU PROGRAMME DE RABAIS ET RÉTENTION À LA CONSOMMATION ("PRRC")

DÉCLARER *que le rapport déposé par Gaz Métro, pièce Gaz Métro-3, Document 4, répond au suivi requis;*

ENTÉRINER *les recommandations formulées dans le rapport d'évaluation;*

À L'ÉGARD DU SUIVI 4 DANS LA DÉCISION D-2011-048 - RAPPORT D'AVANCEMENT DU PROJET D'INCLURE PLUS D'UN POINT DE LIVRAISON POUR LES CLIENTS DÉSIRANT FOURNIR LEUR PROPRE GAZ NATUREL

DÉCLARER *que le dépôt du rapport d'avancement, pièce Gaz Métro-12, Document 2, répond au suivi requis;*

À l'ÉGARD DU SUIVI DANS LA DÉCISION D-2011-073 – PROGRAMMES ET ACTIVITÉS EN EFFICACITÉ ÉNERGÉTIQUE

APPROUVER *le maintien des programmes décrits à la pièce Gaz Métro-9, Document 10;* »

3. PROCESSUS D'ENTENTE NÉGOCIÉE (PEN)

3.1 RAPPORT DÉPOSÉ PAR LE GROUPE DE TRAVAIL

[12] Dans sa décision D-2011-048, la Régie autorisait la mise en place d'un Groupe de travail pour étudier le dossier tarifaire 2012 de Gaz Métro.

[13] Du 13 mai au 8 juin 2011, les membres du Groupe de travail se sont rencontrés à cinq reprises. Au cours de ces rencontres, le Groupe de travail a passé en revue et soumis au PEN tous les sujets lui étant référés dans le cadre de la décision D-2011-048.

[14] Le 8 juin 2011, les membres du Groupe de travail indiquent être d'accord avec le contenu des documents soumis dans le cadre de leur rapport et décrits à la pièce B-0123.

[15] Les membres du Groupe de travail concluent que les documents produits par Gaz Métro respectent le Mécanisme approuvé dans la décision D-2007-47[3] à l'exception de TCE qui s'abstient sur l'ensemble des pièces traitées dans le PEN. Aucun intervenant n'a exprimé de dissidence.

3.2 APPLICATION DU MÉCANISME

3.2.1 ÉTABLISSEMENT DU REVENU REQUIS

[16] Le fonctionnement du Mécanisme est basé sur une comparaison entre le revenu plafond et le revenu requis en début d'exercice.

[17] Lorsque le revenu requis est inférieur au revenu plafond, l'écart est considéré comme un gain de productivité. Ce dernier est partagé à parts égales entre les clients et Gaz Métro sous forme d'ajustement tarifaire, pour les premiers, et de bonification du rendement de base sur l'avoir des actionnaires ordinaires, pour la seconde.

[18] Lorsque le revenu requis est supérieur au revenu plafond, les tarifs sont fixés de manière à générer le revenu requis. Il n'y a alors aucune bonification du taux de rendement de Gaz Métro et celle-ci contracte une dette envers ses clients équivalente à l'écart entre le revenu plafond et le revenu requis.

[19] Le revenu plafond de la composante distribution (D) est établi à partir de celui de l'exercice précédent, lequel est ajusté pour tenir compte de la variation des volumes projetés, de la remise des gains de productivité antérieurs et de l'évolution des prix à la consommation, moins un facteur de productivité. Le revenu plafond est également ajusté pour tenir compte de l'impact des facteurs exogènes et des exclusions. Le revenu plafond des autres composantes, soit le transport (T), l'équilibrage (É) et les inventaires de fourniture et gaz de compression (F, C), est égal au revenu requis déterminé selon la méthode du coût de service.

3 Dossier R-3599-2006.

[20] Le revenu requis de distribution, avant partage, est établi selon les mêmes règles que dans un mode de réglementation basé sur les coûts. Les coûts de distribution comprennent, entre autres, les dépenses d'exploitation, les amortissements, le rendement sur la base de tarification et la contribution au Fonds vert. Les coûts de transport et d'équilibrage sont en majeure partie déterminés par les contrats conclus avec les fournisseurs des services de transport et d'entreposage et les volumes projetés.

[21] L'établissement de l'ensemble des revenus et des coûts fait l'objet d'un PEN. Le tableau suivant présente le calcul du gain de productivité anticipé pour l'année tarifaire 2012, son partage ainsi que le revenu plafond et le revenu requis selon les composantes distribution (D), inventaires de fourniture et gaz de compression (F, C), transport (T) et équilibrage (É), tel qu'indiqué en preuve.

TABLEAU 1
Calcul du gain de productivité et son partage
(000 $)

	2011	**2012**				
	TOTAL(1)	**Distribution (D)**	**Inventaires (F, C)**	**Transport (T)**	**Équilibrage (É)**	**TOTAL**
Revenu plafond	868 811	526 851	5 475	318 043	106 950	957 319
Revenu requis	862 522	511 779	5 475	318 043	106 850	942 246
Gain de productivité	6 289	15 072	-	-	-	15 072
Part des clients	6 289	7 536	-	-	-	7 536
Part de Gaz Métro	0	7 536	-	-	-	7 536
Rendement additionnel de Gaz Métro après impôts	0,0 %	0,72 %	-	-	-	0,72 %

(1) Selon la décision D-2010-149, dossier R-3720-2010 Phase 2, page 6.

Sources : Pièces B-0236, B-0237, B-0238

Note : Les totaux peuvent différer pour cause d'arrondissement.

[22] Le revenu plafond de distribution pour l'année tarifaire 2012 s'établit à 526,9 M$ alors que le revenu requis de distribution est de 511,8 M$. L'ensemble des activités de Gaz Métro lui permet d'anticiper des gains de productivité de son activité de distribution de 15,1 M$ qui seront partagés à parts égales avec les clients.

3.2.2 PRINCIPAUX ÉLÉMENTS DU REVENU REQUIS

[23] Les charges d'exploitation s'élèvent à 167,6 M$ en 2012, soit une hausse nette de 9,0 M$ ou de 5,7 % par rapport à l'année précédente. La variation est attribuable aux éléments suivants[4] :

- l'inflation des salaires : 2,1 M$;
- le fonds de pension : 3,5 M$;
- les autres avantages sociaux : 1,3 M$;
- la formation pour remplacements des départs à la retraite : 0,9 M$;
- le maintien du niveau de Service à la clientèle dû à l'implantation du projet Héritage : 0,7 M$;
- l'inflation des dépenses et l'augmentation du coût de l'essence : 0,5 M$.

[24] La valeur moyenne mensuelle de la base de tarification s'établit à 1 792,3 M$[5], soit une augmentation de 42,8 M$ par rapport au budget révisé (5/7) 2011. Les additions à la base de tarification s'élèvent à 139,2 M$[6] en 2012, en hausse de 15,8 M$ par rapport au budget révisé de 2011. Cette progression s'explique principalement par la hausse des montants relatifs aux améliorations du réseau et aux investissements en développement de réseau.

3.3 PARTICULARITÉS POUR L'ANNÉE TARIFAIRE 2012

[25] Le Groupe de travail fait des demandes spécifiques à la Régie en ce qui a trait à l'efficacité énergétique[7]. Ces demandes sont liées aux interventions de Gaz Métro destinées aux ménages à faible revenu (MFR), ainsi qu'à la rentabilité du Plan global en efficacité énergétique (PGEÉ).

[26] **La Régie prend acte des engagements de Gaz Métro en ce qui a trait aux programmes en efficacité énergétique ciblant les MFR.**

4 Pièce B-0149, page 1.
5 Pièce B-0132, page 1.
6 Pièce B-0128, page 1.
7 Pièce B-0122, pages 2 et 3.

[27] Par ailleurs, tenant compte des amendements apportés par la California Public Utilities Commission (CPUC) à sa méthodologie de calcul du test du coût total en ressources (TCTR), **la Régie autorise Gaz Métro à baliser, en 2012, les méthodologies actuelles de calcul du TCTR, incluant celle de la CPUC, et de proposer, le cas échéant, des modifications au calcul de ce test dans le cadre du PGEÉ 2013.**

[28] **Enfin, la Régie refuse la troisième demande du Groupe de travail d'approuver une modification de la présentation des tableaux de la rentabilité du PGEÉ.** En effet, la Régie juge inopportun que deux résultats du TCTR soient présentés, l'un selon les modalités actuelles et l'autre selon une valeur correspondant à la moyenne mobile sur cinq ans du prix du gaz naturel. L'utilisation de cette valeur ne permet pas d'associer la bonne valeur aux économies d'énergie, à leurs coûts évités et aux gains qui y sont associés, compte tenu que les économies d'énergie utilisées aux fins du calcul du TCTR doivent être réalisées sur une seule année tarifaire[8].

3.4 PGEÉ

3.4.1 RÉSULTATS DU PGEÉ 2011

[29] Après les cinq premiers mois de l'année, les économies nettes du PGEÉ 2011 correspondent à environ 10,6 Mm³, soit 33 % de la prévision annuelle. Pour la même période, les coûts encourus sont de 4,8 M$, soit 38 % de la prévision budgétaire annuelle. Le Groupe de travail prévoit que le budget sera suffisant pour atteindre les objectifs annuels de 2011[9].

3.4.2 OBJECTIFS D'ÉCONOMIE D'ÉNERGIE ET BUDGET DEMANDÉ EN 2012

[30] Pour le PGEÉ 2012, les objectifs d'économie d'énergie sont de 31,2 Mm³ de gaz naturel. Afin de mettre en œuvre le PGEÉ 2012, le budget demandé s'élève à 12,3 M$, dont près de 10,4 M$ d'aide financière. La Régie constate qu'il s'agit d'une baisse de

[8] Pièce B-0207, page 8.
[9] Pièce B-0156, page 12.

2,5 % des objectifs et de 1,6 % des budgets par rapport aux montants autorisés pour le PGEÉ 2011[10].

[31] **La Régie approuve le budget proposé par le Groupe de travail pour le PGEÉ 2012**.

3.4.3 RENTABILITÉ DES PROGRAMMES

[32] Les taux d'actualisation utilisés pour calculer la rentabilité du PGEÉ permettent de considérer la variation des coûts et des bénéfices dans le temps. Depuis 2000, un taux d'actualisation de 8 % est utilisé pour le calcul du TCTR, du test du participant (TP) et du test de neutralité tarifaire (TNT). Un taux d'actualisation de 6 % est cependant utilisé aux fins du calcul du test du coût social (TCS). Ces taux nominaux sont convertis en taux réels en utilisant un facteur d'inflation annuel de 2 %[11].

[33] En 2010, la Régie demandait à Gaz Métro de justifier l'utilisation d'un taux d'actualisation réel de 6 % et de commenter la possibilité d'utiliser le coût du capital prospectif comme taux d'actualisation dans le calcul du TCTR[12].

[34] Après un balisage des taux d'actualisation utilisés par Hydro-Québec et Gazifère inc., le Groupe de travail propose d'utiliser le taux du coût en capital prospectif autorisé par la Régie dans le cadre du dossier tarifaire précédent, afin de mettre à jour annuellement le taux d'actualisation. Ainsi, pour le PGEÉ 2012, le Groupe de travail propose un taux d'actualisation nominal de 6,53 %, soit le taux du coût du capital prospectif autorisé dans la décision D-2010-149[13].

[35] Le Groupe de travail suggère de maintenir le taux d'inflation à 2 %, mais ce taux pourrait être révisé advenant une modification de la politique de la Banque du Canada ou un écart important entre ce taux et l'inflation réelle.

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10 Pièce B-0156, page 6; décision D-2010-144, dossier R-3720-2010 Phase 2, page 18.
11 Pièce B-0156, page 16.
12 Dossier R-3717-2009, pièce B-0009, Gaz Métro-12, document 3.2, réponse à la question 5.2.
13 Décision D-2010-149, dossier R-3720-2010 Phase 2, page 5.

[36] Le taux d'actualisation réel proposé pour 2012 est donc de 4,53 %. Le Groupe de travail considère qu'un taux uniforme pour tous les tests de rentabilité (TCTR, TP, TNT et TCS) est approprié[14].

[37] En audience, S.É./AQLPA appuie le choix d'un taux d'actualisation de 4,53 %, identique pour le TCTR et le TCS et fait valoir que, dans la décision D-2009-046, la Régie a requis de l'Agence de l'efficacité énergétique du Québec que les paramètres économiques du TCS soient les mêmes que ceux du TCTR[15].

[38] **La Régie autorise la mise à jour annuelle du taux d'actualisation utilisé aux fins du calcul du TCTR, du TP, du TNT et du TCS à partir du coût en capital prospectif qu'elle a autorisé dans le cadre du dossier tarifaire précédent et d'un taux d'inflation de 2 %. Ainsi, pour le PGEÉ 2012, la Régie autorise un taux d'actualisation réel uniforme de 4,53 %**.

[39] Par ailleurs, jugeant que cet ajustement est requis pour éviter une surévaluation de la rentabilité, **la Régie prend acte de la correction apportée à la méthode de calcul du TP afin de tenir compte de l'ensemble des coûts incrémentaux des mesures du PGEÉ**[16].

[40] Enfin, la Régie constate que la rentabilité du PGÉE 2012, calculée sur la base du TCTR, est de 123,1 M$, ce qui est supérieur à la rentabilité prévue pour le PGEÉ 2011. Le Groupe de travail justifie cette augmentation de la rentabilité par la modification du taux d'actualisation[17].

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14 Pièce B-0156, pages 16 et 17; pièce B-0207, page 9.

15 Décision D-2009-046, dossier R-3671-2008, page 67; pièce A-0059, pages 138 et 139.

16 Pièce B-0156, page 15.

17 Dossier R-3720-2010 Phase 2, pièce B-17, Gaz Métro-9, document 2, tableau VI.4 : la rentabilité du PGEÉ 2011 était évaluée à 109,7 M$; pièce B-0156, page 6.

3.4.4 IMPACT TARIFAIRE ET RÉPARTITION DES COÛTS DU PGEÉ

[41] L'impact tarifaire des coûts de l'efficacité énergétique sur les revenus de distribution est de 2,6 % en 2012, si les frais reportés sont exclus. En incluant les frais reportés, cet impact est de 2,4 %[18].

[42] Par ailleurs, le Groupe de travail rappelle que la moyenne de participation des deux dernières années complètes est prise en compte au moment de répartir les coûts du PGEÉ par palier tarifaire.

3.4.5 POTENTIEL TECHNICO-ÉCONOMIQUE (PTÉ)

[43] La Régie note le report de l'évaluation du PTÉ du PGEÉ, qui était initialement prévue pour 2011. Ce report s'explique par le fait que Gaz Métro a dû mandater, en janvier 2011, un nouveau consultant pour remplacer le fournisseur initialement responsable de cette évaluation. Le Groupe de travail prévoit cependant déposer l'évaluation du PTÉ dans le cadre du dossier tarifaire 2013[19].

3.4.6 MODIFICATIONS AUX PROGRAMMES ET SUIVI DE DÉCISIONS ANTÉRIEURES OU DE RAPPORTS DE LA RÉGIE

[44] Le Groupe de travail et Gaz Métro proposent des modifications et des ajouts aux programmes du PGEÉ 2012, par rapport au PGEÉ 2011. Bien que certaines de ces modifications fassent suite à des décisions ou des rapports antérieurs de la Régie et n'aient pas été traitées dans le cadre du PEN, la Régie les examine dans la présente section, par souci de cohérence.

[45] Ainsi, le Groupe de travail propose l'ajout du projet-pilote PE123-Combo à condensation.

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[18] Pièce B-0244, pages 21 et 22, tableaux XII.1 et XII.2.
[19] Pièce B-0156, page 12.

[46] Le système combo est composé d'un chauffe-eau au gaz naturel, combiné à un échangeur de chaleur. Cet assemblage permet de répondre aux besoins d'eau chaude sanitaire et de chauffage de l'espace. Plus spécifiquement, le PE123 promeut l'utilisation du chauffe-eau à condensation (à accumulation ou instantané) pour une utilisation en système combo. Le Groupe de travail prévoit 150 participants en 2012 pour ce projet-pilote et l'aide financière prévue est de 550 $ par appareil[20].

[47] **Compte tenu que la description, la justification ainsi que les hypothèses qui y sont associées sont satisfaisantes, la Régie approuve le PE123-Combo à condensation ainsi que ses paramètres**.

[48] Afin de valider plus précisément l'impact énergétique du PE208-Encouragement à l'implantation (marché affaires), à la suite d'une demande de la Régie, Gaz Métro propose une méthode d'évaluation quantitative des économies d'énergie. Gaz Métro propose également que cette méthode soit appliquée aux PE218-Encouragement à l'implantation (marché industriel) et PE219-Encouragement à l'implantation (marché institutionnel), deux programmes similaires[21].

[49] **La Régie considère que la proposition de Gaz Métro répond au suivi requis et l'autorise à procéder à l'évaluation quantitative des économies d'énergie des PE208, PE218 et PE219 selon la méthode proposée. La Régie approuve également l'échéancier proposé ainsi que le budget requis pour la réalisation du projet, lequel budget est inclus au PGEÉ.**

[50] Cependant, étant donné que l'évaluation quantitative des économies d'énergie des PE208, PE218 et PE219 indique une surestimation ou une sous-estimation systématique des gains énergétiques, la Régie rappelle à Gaz Métro l'importance de reconsidérer le gain unitaire ainsi que l'aide financière de ces programmes pour les dossiers tarifaires à venir.

[51] Dans son rapport d'examen sur l'évaluation du PE103-Thermostat électronique programmable, la Régie s'interroge sur la nécessité de maintenir ce programme actif dans son format actuel, compte tenu que le taux de pénétration du programme est supérieur à

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20 Pièce B-0156, pages 24 à 26.
21 Pièce B-0059, pages 4 à 16.

46 % de la clientèle visée et que 97 % des participants installent un thermostat lors de l'achat d'une nouvelle résidence ou lors du remplacement de leur système de chauffage[22].

[52] Selon Gaz Métro, le potentiel résiduel du PE103 est encore significatif. L'évaluation du PTÉ, dont le dépôt est prévu dans le cadre du dossier tarifaire 2013, permettra de quantifier ce potentiel. Gaz Métro souligne également que le taux de satisfaction des participants au PE103 est élevé et propose de le maintenir parmi les programmes du PGEÉ 2012, tout en y intégrant les modifications résultant de l'évaluation[23].

[53] En réponse à une demande spécifique de la Régie, Gaz Métro indique ne pas avoir envisagé une combinaison des PE103 et PE111-Chaudières efficaces, puisque cela aurait pour effet de limiter le nombre de participants au PE103[24].

[54] Cependant, la Régie note que seulement 30 % des participants au PE103 n'ont participé à aucun autre programme résidentiel du PGEÉ visant les systèmes de chauffage ou les chauffe-eau[25].

[55] Considérant cet élément, le taux de participation observé en 2010 pour le PE103, ainsi que les conclusions de son rapport d'examen sur l'évaluation du programme, **la Régie demande à Gaz Métro de proposer, dans le cadre du PGEÉ 2013, une nouvelle approche résidentielle qui optimiserait les contacts avec les participants et assurerait une meilleure rentabilité future à tous les programmes, notamment le PE103.**

[56] La Régie, dans son rapport de suivi 2011 des évaluations du PGEÉ, considérait que les rapports d'évaluation des PE202-Chaudière à efficacité intermédiaire et PE210-Chaudières à condensation ne permettaient pas de valider entièrement l'impact énergétique de ces programmes. La Régie était notamment préoccupée par le fait que Gaz Métro ne possédait pas de données sur la quantité de chaudières installées sur son territoire ainsi que sur leur efficacité, ni d'information à l'égard du parc d'équipements de ses clients[26].

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22 Suivi 2011 des évaluations des programmes du PGEÉ et du FEÉ de Gaz Métro, 28 avril 2011, page 16.
23 Selon Gaz Métro, 88 % des participants se déclarent satisfaits du programme : pièce B-0156, pages 20 et 21.
24 Pièce B-0207, page 11.
25 Pièce B-0266.
26 Suivi 2011 des évaluations des programmes du PGEÉ et du FEÉ de Gaz Métro, 28 avril 2011, pages 22 et 35.

[57] **La Régie note que Gaz Métro compte se pencher sur cet élément, mais lui demande de présenter ses recommandations à cet égard dans le cadre du PGEÉ 2013, plutôt que dans le cadre d'un prochain dossier tarifaire ou d'une prochaine évaluation du programme**[27].

[58] La Régie, dans son rapport de suivi 2011 des évaluations du PGEÉ, concluait que le résultat du calcul du taux de bénévolat du PE212-Chauffe-eau à condensation semblait anormalement élevé, compte tenu des objectifs annuels du programme. La Régie émettait une réserve quant à l'utilisation de cette hypothèse tant que l'évaluation spécifique du PE212 n'aurait pas été déposée et examinée[28].

[59] Gaz Métro indique que la méthode de calcul appliquée pour évaluer l'effet de bénévolat du PE212 est la même que celle utilisée pour évaluer l'effet de bénévolat de neuf autres programmes et qu'elle a été jugée opportune par la Régie. Dans ce contexte, le distributeur intègre, dès le présent dossier, l'ensemble des données mises à jour aux paramètres du PE212, incluant les économies d'énergie de 457 100 m^3 associées au bénévolat.

[60] Pour mesurer l'effet de bénévolat, Gaz Métro propose de communiquer avec des non-participants à des fins de vérification, en 2013 et 2014. Gaz Métro explique ce délai par la nécessité d'éviter la sursollicitation des non-participants[29].

[61] Bien que la méthode de calcul du taux de bénévolat du PE212 soit utilisée pour plusieurs programmes et que les hypothèses qui la sous-tendent aient effectivement été jugées appropriées, la Régie maintient ses réserves quant aux résultats de son application au PE212. Dans ce contexte, la Régie considère que l'exercice de vérification proposé par Gaz Métro est valable. Cependant, compte tenu que les ajustements aux gains énergétiques des programmes sont apportés de façon strictement prospective[30], des économies d'énergie de 457 100 m^3/an seront créditées pour le bénévolat du PE212 sans qu'un ajustement *a posteriori* ne soit prévu, si les résultats de l'exercice de vérification devaient infirmer les hypothèses retenues.

[27] Pièce B-0156, pages 30 et 34.
[28] Suivi 2011 des évaluations des programmes du PGEÉ et du FEÉ de Gaz Métro, 28 avril 2011, page 11.
[29] Pièce B-0156, pages 35 et 36.
[30] Pièce B-0207, page 12.

[62] **Tenant compte de ce qui précède, la Régie ordonne à Gaz Métro d'appliquer, comme par le passé, un taux de bénévolat de 0 % au PE212[31] jusqu'à l'obtention des résultats de l'exercice de vérification qu'elle propose**.

[63] Dans la décision D-2011-073, la Régie demandait à Gaz Métro d'élaborer sur la notion de tendanciel et sur le fait que 42 % des économies d'énergie du PGEÉ 2010 étaient associées aux PE207-Études de faisabilité (CII[32]) et PE211-Études de faisabilité (VGE[33]). Dans cette décision, la Régie demandait également à Gaz Métro d'élaborer sur l'ampleur que prennent ces programmes sur les objectifs, les résultats et la rentabilité du PGEÉ[34].

[64] Selon Gaz Métro, les économies attribuables aux PE207 et PE211 ne peuvent être considérées comme des économies tendancielles puisqu'elles sont le résultat de mesures d'efficacité énergétique qui vont au-delà des façons de faire courantes et qui n'auraient pas été identifiées sans l'intervention d'un ingénieur spécialisé. Cependant, Gaz Métro reconnaît qu'il se peut que des études de faisabilité de la même nature que celles promues par les PE207 et PE211 soient réalisées par des non-participants non influencés par ces programmes[35].

[65] La Régie considère que l'existence de ces « *non-participants non influencés ayant réalisé des études de faisabilité* » indique que le tendanciel associé à ces programmes diffère de zéro. La Régie ne souscrit pas, par ailleurs, à l'opinion de Gaz Métro, qui affirme :

> « […] ces études, *que ça soit tendanciel ou que ça ne soit pas tendanciel, à notre avis ça n'a aucun lien direct avec les économies* […] *qui sont générées par les programmes du PGEÉ. Donc, il peut bien y en avoir, mais ça ne fait pas partie des économies générées*[36]. »

[66] La Régie précise que le tendanciel doit être considéré au moment de la comptabilisation des économies d'énergie qu'il réduit. En effet, si une tendance à l'économie d'énergie existe déjà pour une mesure donnée, les nouvelles économies

31 Dossier R-3720-2010 Phase 2, pièce B-17, Gaz Métro-9, document 2, page 15.
32 Commercial, institutionnel et industriel.
33 Ventes grandes entreprises.
34 Décision D-2011-073, dossier R-3745-2010, page 21.
35 Pièce B-0119, pages 4 et 9; pièce A-0048, pages 15 et 16.
36 Pièce A-0048, page 16.

d’énergie générées seront moindres que pour une mesure implantée là où la tendance est inexistante. Ce sont les économies d’énergie marginales qui importent et qui justifient les programmes d’efficacité énergétique.

[67] **Considérant que le tendanciel associé aux PE207 et PE211 n’est pas nul, la Régie demande à Gaz Métro d’émettre une hypothèse documentée à cet égard, différente de 0 %, dans le cadre du PGEÉ 2013.**

[68] Par ailleurs, Gaz Métro reconnaît que les résultats réels combinés des PE207 et PE211 ont représenté, respectivement, 18 %, 29 % et 42 % des résultats de 2008, 2009 et 2010, soit une progression importante. Selon Gaz Métro, cette variation est presque entièrement attribuable au PE211.

[69] Gaz Métro précise que les résultats plus élevés observés en 2010 sont liés à la participation simultanée de quatre clients majeurs ainsi qu’à une participation générale supérieure à la prévision[37].

[70] En ce qui a trait au PE207, la Régie constate que les économies d’énergie moyennes attribuées à chacun des participants croissent substantiellement entre 2011 et 2012. En effet, les objectifs d’économie d’énergie passent de 748 464 m^3 en 2011 à 947 136 m^3 en 2012, bien que le nombre de participants demeure le même. Il en résulte une économie d’énergie moyenne de 15 925 m^3/participant en 2011 et de 20 152 m^3/participant en 2012. Il s’agit d’une hausse de près de 27 %, qui ne peut être justifiée par les résultats réels de 2010[38].

[71] En ce qui a trait au PE211, la Régie observe que, malgré les explications fournies par Gaz Métro quant à la participation exceptionnelle de quatre clients majeurs, les objectifs d’économie d’énergie de 2011 demeurent au même niveau que les résultats observés en 2010. Néanmoins, la Régie observe une forte diminution des objectifs moyens par participant entre 2012 et 2011[39].

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[37] Pièce B-0119, pages 10 et 11.

[38] Dossier R-3720-2010 Phase 2, pièce B-17, Gaz Métro-9, document 2, page 7; pièce B-0244, page 7; dossier R-3745-2010, pièce B-0042, page 42 : les économies d’énergie réelles associées aux 50 participants étaient de 679 380 m^3, soit 13 588 m^3/participant, en moyenne.

[39] Dossier R-3720-2010 Phase 2, pièce B-17, Gaz Métro-9, document 2, page 7 : les économies d’énergie prévues en 2011 sont de 9 709 024 m^3 pour 24 participants, soit 404 543 m^3/participant; dossier R-3745-2010, pièce B-0042, page 45 : les économies d’énergie réelles associées aux 30 participants de 2010 étaient de 12 902 948 m^3, soit 430 098 m^3/participant, en moyenne; pièce B-0244, page 7 : les objectifs de 2012 sont de 3 823 750 m^3 pour 33 participants, soit 115 871 m^3/participant, en moyenne.

[72] **La Régie considère que l'explication fournie par Gaz Métro quant à la part des économies d'énergie due aux PE207 et PE211 ne répond que partiellement à sa requête et demande à Gaz Métro de compléter sa réponse lors du rapport annuel 2011, en se penchant, notamment, sur le niveau des économies d'énergie moyennes du PE211, ainsi que sur la croissance anticipée des économies d'énergie moyennes du PE207. La Régie demande également à Gaz Métro de justifier tout écart majeur entre les objectifs fixés et les résultats observés, pour ces deux programmes**.

[73] Dans la décision D-2011-073, la Régie s'inquiétait de la non-rentabilité de quatre programmes du PGEÉ, soit les PE113-Chauffe-eau instantané, PE212-Chauffe-eau à condensation, PE215-Infrarouge (CII) et PE217-Infrarouge (VGE)[40].

[74] Bien que le projet-pilote PE113 demeure non rentable en 2012, Gaz Métro fait valoir qu'il permet une transformation du marché qui justifie son maintien dans le PGEÉ 2012[41]. **Dans ce contexte, la Régie autorise Gaz Métro à poursuivre en 2012 ses interventions dans le cadre du projet-pilote PE113**.

[75] Par ailleurs, compte tenu que le PE212 devient rentable dès 2012 et que la rentabilité combinée des PE217 et PE215 s'avère positive dès 2012, **la Régie autorise Gaz Métro à maintenir ces programmes et le projet-pilote dans le PGEÉ 2012**.

[76] Enfin, considérant qu'elles sont suffisamment justifiées et satisfaisantes, **la Régie approuve l'ensemble des autres modifications proposées par le Groupe de travail aux programmes du PGEÉ et à leurs paramètres.**

3.4.7 ÉVALUATION DES PROGRAMMES

[77] La Régie prend acte du calendrier des évaluations 2012 proposé par le Groupe de travail. Elle note également l'intention de Gaz Métro de présenter en même temps que son rapport annuel 2011, pour un examen par voie administrative, l'évaluation du PE113,

40 Décision D-2011-073, dossier R-3745-2010, page 21.
41 Pièce B-0119, pages 13, 14 et 17.

l'évaluation des effets de distorsion du PE213-Chaudière et chauffe-eau efficace ainsi que l'évaluation des effets de bénévolat des programmes VGE[42].

[78] **À cet égard, la Régie demande à Gaz Métro de tenir compte, lors de l'interprétation des résultats de l'évaluation du PE113, du fait que son aide financière a déjà été réduite**.

3.5 PROGRAMME DE FLEXIBILITÉ TARIFAIRE

[79] Gaz Métro demande à la Régie de reconduire, jusqu'au 30 septembre 2013, le programme de flexibilité tarifaire pour le mazout et la biénergie pour les clients des tarifs D_1 et D_3 déjà reconduit jusqu'au 30 septembre 2012 par la décision D-2010-144[43].

[80] Ce programme vise à prévenir des pertes de volumes et de revenus de transport et de distribution. Gaz Métro démontre que le programme et sa gestion sont à l'avantage des clients en prévenant, notamment, des hausses tarifaires pour ceux-ci.

[81] **La Régie reconduit, jusqu'au 30 septembre 2013, les programmes de flexibilité tarifaire mazout et biénergie aux clients des tarifs D_1 et D_3.**

3.6 ÉTABLISSEMENT DES TARIFS

[82] Les tarifs sont fixés de manière à générer un revenu requis totalisant 949,8 M$[44]. Ce montant correspond au revenu plafond duquel est déduite la part des clients des gains de productivité.

[83] La baisse des tarifs de distribution qui s'ensuit s'établit à 0,23 %. Cette baisse provient de l'effet combiné des variations des volumes de gaz naturel consommés, du revenu plafond et du revenu requis.

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[42] Pièce B-0156, pages 10 et 11.
[43] Décision D-2010-144, dossier R-3720-2010 Phase 2, page 22.
[44] Pièce B-0239, page 1.

[84] Le tableau suivant présente le détail des calculs de l'ajustement tarifaire.

TABLEAU 2
Calcul de l'ajustement tarifaire global demandé en 2011
(000 $)

	Distribution (D)	**Inventaires (F, C)**	**Transport (T)**	**Équilibrage (É)**	**TOTAL**
Revenu plafond	526 851	5 475	318 043	106 950	957 319
Gains de productivité (à rembourser aux clients)	(7 536)				(7 536)
Revenu requis (1)	519 315	5 475	318 043	106 950	949 782
Tarifs 2009-2010 (2)	520 513	6 854	368 366	58 527	954 260
Ajustement tarifaire	(1 198)	(1 380)	(50 323)	48 423	(4 477)
Variation	***-0,23 %***	***-20,13 %***	***-13,66 %***	***82,73 %***	*-0,47 %*

(1) Revenu requis à récupérer dans les tarifs.
(2) Tarifs en vigueur en 2011 appliqués aux volumes projetés de 2012.
Source : Pièce B-0239, page 1
Note : Les totaux peuvent différer pour cause d'arrondissement.

[85] **La Régie rendra sa décision finale sur le revenu requis et les ajustements tarifaires lorsqu'elle recevra les informations demandées dans la présente décision.**

3.7 CONCLUSION SUR LE RAPPORT DU GROUPE DE TRAVAIL

[86] **La Régie approuve, pour l'année tarifaire 2012, la proposition du Groupe de travail en ce qui a trait à l'application du mécanisme incitatif à l'amélioration de la performance approuvé dans sa décision D-2007-47, sous réserve des modifications à apporter, conformément à la présente décision.**

[87] **La Régie demande au distributeur de réviser et de déposer, au plus tard le 7 décembre 2011 à 12 h, après consultation du Groupe de travail, l'ensemble des pièces nécessaires à l'établissement des tarifs de l'année 2012 en y appliquant les modifications contenues à la présente décision.**

[88] **Compte tenu que la date d'émission de la présente décision est postérieure au 1er octobre 2011 et que les tarifs en vigueur ont été déclarés provisoires par la décision D-2011-153, la Régie autorise Gaz Métro à porter à un compte de frais reportés le manque à gagner résultant du report de l'application des nouveaux tarifs.**

4. SUJETS TRAITÉS EN AUDIENCE

4.1 PLAN D'APPROVISIONNEMENT GAZIER — HORIZON 2012-2014

[89] Tel que requis par le *Règlement sur la teneur et la périodicité du plan d'approvisionnement*[45] (le Règlement sur le plan), Gaz Métro dépose son plan d'approvisionnement gazier pour approbation, conformément à l'article 72 de la *Loi sur la Régie de l'énergie*[46] (la Loi). Ce plan présente la prévision triennale de la demande de gaz naturel ainsi que les outils d'approvisionnement requis pour satisfaire cette demande.

4.1.1 DEMANDE DE GAZ NATUREL

[90] Les livraisons globales, avant interruptions, pour les années 2012 à 2014 sont présentées au tableau suivant.

45 (2001) 133 G.O. II, 6037.
46 L.R.Q., c. R-6.01.

TABLEAU 3
Livraisons globales de gaz naturel 2012–2014
(avant interruptions)[47]
(millions de m³)

	2012	2013	2014
Service continu	4 090,3	4 030,1	4 012,3
Service interruptible	1 216,1	1 164,6	1 176,3
Total	5 306,4	5 194,6	5 188,7

4.1.2 CONTEXTE ET STRATÉGIES D'APPROVISIONNEMENT

[91] Selon le distributeur, l'objectif premier du plan d'approvisionnement est de procurer aux clients un approvisionnement sécuritaire, tout en s'assurant que le coût d'utilisation du gaz naturel soit le plus bas possible et concurrentiel avec celui des autres sources d'énergie. Plus particulièrement, le distributeur contracte les outils nécessaires afin de rencontrer la demande continue des clients en journée de pointe, la demande saisonnière des clients en service continu et, dans la mesure du possible, celle des clients en service interruptible. Ces approvisionnements doivent être suffisamment flexibles pour faire face aux fluctuations dues au climat et à l'activité économique.

[92] Le distributeur vise à minimiser les coûts totaux d'approvisionnement en utilisant une combinaison d'outils. Sa stratégie favorise le recours à un portefeuille échelonné dans le temps et diversifié géographiquement.

[93] Concurremment à l'augmentation des tarifs de TransCanada Pipelines Limited (TCPL), le différentiel de lieu à Dawn a baissé de façon importante. Le présent contexte amène Gaz Métro à envisager, pour les prochaines années, des modifications à sa structure d'approvisionnement.

47 Pièce B-0351, page 44.

Fourniture de gaz naturel

[94] La stratégie d'approvisionnement du distributeur varie en fonction du point d'acquisition.

[95] En 2012, plus de 80 % des achats de gaz naturel se feront à Dawn. Le distributeur privilégie des contrats à court terme à Dawn afin d'optimiser l'appariement des achats avec la demande et de moduler le tout en fonction de la variation de cette demande, tant sur une base mensuelle, annuelle que pluriannuelle. Certaines strates minimales peuvent être contractées pour des durées supérieures à un an. Gaz Métro demeure prudente quant à ses achats à plus long terme afin de conserver toute la flexibilité dont elle pourrait avoir besoin si le contexte changeait.

[96] Au point d'acquisition Empress, Gaz Métro effectuera les achats requis quotidiennement, sur une base *spot*. Gaz Métro ne procédera donc pas à un appel d'offres cette année.

Transport

[97] Dans sa décision D-2009-156[48], la Régie demandait à Gaz Métro de présenter, dans le cadre du présent dossier tarifaire, une analyse de rentabilité en matière de renouvellement des contrats de transport *Firm Transmission Short Haul* (FTSH) et *Firm Transmission Long Haul* (FTLH).

[98] Gaz Métro poursuit son objectif de réduire ses coûts de transport en diminuant la capacité longue distance entre l'Alberta et sa franchise et en y jumelant des achats à Dawn. Le gaz naturel acheté à Dawn est transporté en vertu d'un contrat de courte distance dont les coûts sont moindres. Au cours de la dernière année, Gaz Métro a décontracté un total de 1 866 10^3m^3/jour dans l'ouest canadien. Une partie de cette capacité de transport (97 10^3m^3/jour) a cependant été remplacée par des contrats sur le marché secondaire et par des capacités de transport détenues directement par ses clients. Une nouvelle méthode d'évaluation des interruptions a résulté en des capacités de

48 Dossier R-3690-2009.

transport excédentaire de 1056 10^3m^3/jour qui font partie des 1866 10^3m^3/jour décontractés.

[99] **La Régie prend acte du suivi déposé par Gaz Métro.**

Équilibrage

[100] Le portefeuille d'outils d'équilibrage de Gaz Métro est constitué en partie de trois sites d'entreposage souterrain et de l'usine de gaz naturel liquide (GNL) dont elle est propriétaire. L'autre partie consiste en des achats effectués à Dawn.

4.1.3 PLANIFICATION ANNUELLE 2012

4.1.3.1 Détermination de la demande de la journée de pointe pour l'année tarifaire 2012

[101] Pour l'année 2012, Gaz Métro établit à 27 489 10^3m^3/jour la demande de la journée de pointe. Le distributeur estime à 27 757 10^3m^3/jour les outils d'approvisionnement requis pour répondre à l'hiver extrême.

[102] **La Régie considère que ces valeurs ont été dérivées conformément à la méthodologie acceptée dans la décision D-2009-156.**

4.1.3.2 Revenus d'optimisation

[103] Les revenus d'optimisation découlent des transactions opérationnelles et des transactions financières touchant les outils d'approvisionnement.

[104] Le distributeur distingue, parmi les transactions opérationnelles, les reventes de transport *a priori*, qui sont normalement effectuées avant que l'année ne débute, et les reventes de transport FTLH, réalisées en cours d'année. Aucune vente de transport *a priori* n'est prévue en 2012.

TRANSACTIONS OPÉRATIONNELLES

Revente en cours d'année du transport excédentaire FTLH

[105] Gaz Métro prévoit des ventes en cours d'année de transport FTLH inutilisé de 2,2^{6}m^3 à un prix moyen de 2,614 ¢/m^3, ce qui correspond à un montant total de 0,06 M$. Le prix de revente a été projeté en appliquant la méthode retenue dans la décision D-2009-156.

[106] **La Régie accepte les prix de revente qui résultent de l'application de la formule, tel que proposé par Gaz Métro.**

TRANSACTIONS FINANCIÈRES

[107] Gaz Métro propose de projeter les revenus des transactions financières à 5,9 M$. Ce montant correspond à l'hypothèse retenue par la Régie lors du dernier dossier tarifaire. La Régie note que les revenus d'optimisation prévus de l'année en cours sont du même ordre de grandeur.

[108] **En conséquence, la Régie retient comme estimation vraisemblable des revenus de transactions financières une prévision de 5,9 M$.**

4.1.4 PLAN D'APPROVISIONNEMENT 2012-2014

[109] La Régie note que le portefeuille d'approvisionnement rencontre les besoins annuels, saisonniers et de pointe de la clientèle.

4.1.4.1 Capacité de transport C1

[110] Gaz Métro a donné suite à la décision D-2010-144 en ajustant à la baisse les capacités de transport C1. Les besoins ont été réévalués à la suite de la signature d'un contrat d'échange. Elle a également ajusté la capacité en fonction de la réduction de la

capacité contractée de transport FTLH. Ces mesures prennent effet en avril 2013, compte tenu du préavis requis de deux ans.

[111] Les capacités actuellement détenues par Gaz Métro sont de 4 485 10^3m^3/jour et passeront à 4 074 10^3m^3/jour au 1er avril 2012 et à 2 639 10^3m^3/jour au 1er avril 2013. Gaz Métro évalue l'économie de coûts à 0,4 M$ annuellement.

[112] La Régie est satisfaite de la méthodologie présentée par Gaz Métro pour évaluer les besoins de transport C1 et de la réduction des capacités détenues qui en découle.

4.1.4.2 Capacité de transport M12

[113] Gaz Métro a donné suite à la décision D-2010-144 de la Régie demandant d'ajuster à la baisse la capacité de transport M12. Ces mesures prennent effet le 1er avril 2013, compte tenu du préavis requis de deux ans. L'impact sur les coûts, tel que présenté par Gaz Métro, est de 0,05 M$ annuellement.

[114] La Régie est satisfaite de la réduction des capacités détenues qui en découle.

4.1.4.3 Renouvellement d'une capacité d'entreposage auprès de Union Gas

[115] Au cours des dernières années, constatant qu'une portion importante de la capacité d'entreposage détenue par Gaz Métro chez Union viendrait prochainement à échéance, la Régie demandait à Gaz Métro de présenter une preuve complète relative aux enjeux soulevés par le renouvellement des dites capacités de stockage. Dans sa décision au dossier tarifaire 2010, la Régie s'exprimait ainsi :

> « […] *la Régie demande au distributeur de déposer, dans le cadre du prochain dossier tarifaire, une étude complète et étoffée portant sur le renouvellement des capacités de stockage auprès de Union Gas. Cette étude devra présenter une analyse économique permettant d'établir les quantités optimales de stockage pour des fins opérationnelles et les quantités optimales de stockage pour répondre aux fluctuations saisonnières de la demande, en tenant compte des options disponibles, du prix de ces dernières ainsi que du coût du stockage. Des analyses de sensibilité au coût du stockage devront être présentées*[49]. »

[49] Décision D-2009-156, dossier R-3690-2009, pages 35 et 36

[116] Plus récemment, dans la décision D-2010-144, la Régie, tout en prenant acte des besoins de flexibilité opérationnelle de Gaz Métro et donnant son accord à l'étalement des dates de renouvellement, précisait que la quantité et les modalités d'entreposage devaient de nouveau faire l'objet d'une justification complète au prochain dossier tarifaire[50].

[117] Après avoir considéré l'ensemble de la preuve soumise par Gaz Métro, la Régie en arrive à la conclusion que le distributeur n'a pas répondu de façon satisfaisante à cette dernière exigence de la Régie. Les motifs étayant cette conclusion sont présentés dans une section confidentielle de la présente décision, contenue à l'annexe 3[51].

4.1.4.4 Clause 10 jours d'interruption supplémentaires

[118] Dans la décision D-2010-144[52], la Régie demandait à Gaz Métro de former un groupe de travail pour examiner la question du nombre de jours d'interruption et les principes d'établissement du tarif d'équilibrage pour la clientèle interruptible. Le groupe de travail devait examiner aussi le tarif d'équilibrage pour les clients en gaz d'appoint concurrence (GAC).

[119] De façon plus spécifique, la Régie précisait dans sa décision les éléments à considérer :

- la fixation du nombre de jours d'interruption inscrit au texte des *Conditions de service et Tarif*, lors de l'hiver extrême et lors de l'hiver normal;
- la méthode de répartition des coûts d'équilibrage et facteurs inducteurs pertinents;
- les paramètres utilisés pour la fixation des tarifs;
- la nécessité de retenir les 10 jours supplémentaires d'interruption au texte des *Conditions de service et Tarif*.

[120] Dans un premier temps, Gaz Métro propose d'apporter des modifications à la méthode utilisée pour établir le nombre de jours d'interruption maximum à inclure au texte des *Conditions de service et Tarif*. Les principales modifications apportées touchent

50 Décision D-2010-144, dossier R-3720-2010 Phase 2, pages 38 et 39.
51 La Régie permet cependant aux intervenants ayant convenu d'une entente de confidentialité et de non-divulgation de consulter ladite section.
52 Décision D-2010-144, dossier R-3720-2010 Phase 2, page 42.

les volumes prévus pour la clientèle interruptible, le traitement de l'entreposage à Pointe-du-Lac, la définition de la marge opérationnelle et la définition d'un hiver maximum, plus froid que l'hiver extrême[53].

[121] Gaz Métro juge, qu'avec la méthode proposée, elle sera en mesure de respecter le nombre maximum de jours d'interruption et qu'il n'y a plus lieu de maintenir au texte des *Conditions de service et Tarif* la clause des 10 jours d'interruption supplémentaires.

[122] La FCEI propose de maintenir la clause des 10 jours d'interruption supplémentaires. L'intervenante associe cette recommandation à sa proposition sur le calcul du prix de l'équilibrage pour les clients interruptibles. Cet enjeu est traité à la section suivante de la présente décision.

[123] **La Régie prend acte de la méthode modifiée d'établissement du nombre maximum de jours d'interruption à inscrire au texte des *Conditions de service et Tarif*. Elle est d'avis, comme Gaz Métro, qu'avec cette méthode il n'est plus nécessaire de maintenir la clause des 10 jours supplémentaires d'interruption et autorise donc son retrait du texte des *Conditions de service et Tarif*.**

4.1.4.5 Prix d'équilibrage

[124] Le distributeur ne propose aucune modification au calcul du prix d'équilibrage pour les clients interruptibles dans le cadre du présent dossier. Il explique avoir présenté au groupe de travail une nouvelle méthode pour fonctionnaliser les coûts d'équilibrage entre l'espace et la pointe qui permettrait une meilleure allocation des coûts de pointe et d'espace entre les clients continus et interruptibles.

[125] Gaz Métro juge toutefois que les réflexions doivent se poursuivre, puisque les travaux portant sur l'évaluation du coût évité et du crédit à allouer aux clients interruptibles n'ont pas été complétés. Elle indique que la révision du tarif d'équilibrage pourra se faire une fois cette nouvelle méthode d'allocation des coûts mise en place.

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53 Un hiver défini en majorant les degrés-jour (DJ) et les vitesses de vent normaux des mois de novembre à mars d'un pourcentage, spécifique à chacun des mois, basé sur les maximums historiques de chaque mois au cours des 20 dernières années.

[126] Gaz Métro propose cette année une nouvelle fonctionnalisation des coûts entre les services de transport et d'équilibrage. Cette modification a pour effet d'augmenter considérablement les coûts d'équilibrage, comparativement aux coûts 2011, et occasionne un effet à la baisse sur le prix minimum d'équilibrage.

[127] En effet, le prix minimum calculé au dossier tarifaire 2012 serait de -5,126 ¢/m³. Il s'agit du plus bas prix minimum calculé depuis l'instauration de celui-ci au 1er octobre 2005. Ce prix est largement inférieur au prix minimum de -1,561 ¢/m³ établi au dossier tarifaire 2011.

[128] Selon le distributeur, un prix minimum établi à -5,126 ¢/m³ aurait pour effet d'augmenter considérablement les crédits octroyés aux clients ayant des profils de consommation inverses et, plus particulièrement, ceux octroyés aux clients interruptibles au volet A.

[129] Gaz Métro juge non souhaitable l'effet à la hausse du crédit octroyé à ces clients. Cette hausse va à contre sens des réflexions à venir sur le tarif d'équilibrage qui pourraient conduire à une baisse éventuelle des crédits d'équilibrage.

[130] Gaz Métro propose donc le maintien du prix minimum d'équilibrage à -1,561 ¢/m³ tel qu'établi au dossier R-3720-2010, de façon à éviter l'accroissement des crédits octroyés et la volatilité du prix d'équilibrage.

[131] La FCEI propose de modifier, dès cette année, le nombre de jours d'interruption utilisé dans le calcul du prix de l'équilibrage des clients interruptibles. L'intervenante propose de maintenir la clause des 10 jours, mais de soustraire ces 10 jours du nombre maximum de jours d'interruption inscrit au texte des *Conditions de service et Tarif*. De cette façon, le distributeur a toujours accès au même nombre de jours d'interruption, sauf que s'il souhaite utiliser les 10 derniers jours, il doit verser une compensation aux clients.

[132] En réponse à une demande de renseignements de la Régie, la FCEI mentionne qu'il est envisageable de ne pas limiter à 10 le nombre de jours pour lesquels une compensation devrait être versée aux clients dans la formule de calcul du prix d'équilibrage qu'elle propose[54].

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[54] Pièce C-FCEI-0030, page 2.

[133] De plus, la FCEI constate que Gaz Métro inclut dans l'établissement du nombre de jours maximum d'interruption une marge opérationnelle permettant de compenser les erreurs de prévisions météorologiques et les interruptions en bloc. L'intervenante juge que la partie de la marge opérationnelle prévue pour les interruptions en bloc ne sert qu'à accommoder les clients interruptibles et que ces jours d'interruption ne sont pas utiles au distributeur. Elle propose donc de ne pas inclure ces jours d'interruption dans le calcul du tarif d'équilibrage.

[134] L'UMQ propose de considérer, dans le calcul du prix d'équilibrage, dès cette année, le nombre maximum de jours d'interruption sous le scénario de l'hiver extrême après prise en compte de la marge opérationnelle. L'intervenante propose d'appliquer cette méthode, de façon temporaire en 2012, dans l'attente des conclusions de la réflexion sur le tarif d'équilibrage.

[135] L'UMQ indique toutefois ne pas s'opposer à ce que la notion d'un hiver maximum[55] soit considérée dans le plan d'approvisionnement et pour déterminer le nombre maximum de jours d'interruption à inscrire aux *Conditions de service et Tarif*.

[136] En réponse à une demande de renseignements de la Régie, Gaz Métro indique qu'il est possible d'utiliser un nombre de jours d'interruption inférieur au nombre maximum prévu aux *Conditions de service et Tarif* dans le calcul du prix d'équilibrage. Le distributeur indique que, dans cette situation, il pourrait envisager une compensation pour les clients interruptibles lorsque le nombre réel de jours d'interruption dépasse le nombre de jours utilisé dans le calcul du prix d'équilibrage. Dans le contexte où le groupe de travail n'a pas terminé ses réflexions sur le service d'équilibrage, Gaz Métro juge toutefois prématuré la mise en place d'une telle modification potentiellement temporaire.

[137] Compte tenu que les travaux du groupe de travail sur le tarif d'équilibrage ne sont pas complétés, **la Régie accepte la proposition de Gaz Métro de ne pas apporter de changement à la formule de calcul du prix d'équilibrage de la clientèle interruptible. Elle accepte également de maintenir, pour 2012, le tarif minimum d'équilibrage à -1,561 ¢/m^3 de façon à éviter un accroissement des crédits d'équilibrage accordés aux clients interruptibles.**

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[55] Un hiver défini en majorant les degrés-jour (DJ) et les vitesses de vent normaux des mois de novembre à mars d'un pourcentage, spécifique à chacun des mois, basé sur les maximums historiques de chaque mois au cours des 20 dernières années.

[138] **La Régie demande toutefois à Gaz Métro de retenir, dans la réflexion sur la révision du tarif d'équilibrage, le principe visant à dissocier le nombre de jours d'interruption maximum à inscrire au texte des *Conditions de service et Tarif* et le nombre de jours d'interruption à utiliser pour établir le tarif d'équilibrage. Elle lui demande également de retenir le principe visant à compenser les clients interruptibles dans les cas où le nombre de jours d'interruption réel est plus grand que le nombre de jours utilisé dans le calcul du tarif.**

[139] Gaz Métro propose une méthode pour réviser annuellement le tarif d'équilibrage des clients consommant du GAC. Dans le cadre du dossier tarifaire 2003, ce tarif avait été fixé au prix moyen d'équilibrage appliqué au tarif D_4 et n'a pas été modifié depuis.

[140] À partir du profil annuel de consommation de l'ensemble des clients consommant du GAC pour 2009-2010, le distributeur établit que le prix d'équilibrage 2011-2012 serait de 0,356 ¢/m^3. Il note que ce prix se situe entre celui appliqué à un client ayant un profil de consommation parfaitement stable (0,00 ¢/m^3) et le prix pour le profil de consommation moyen de l'ensemble de la clientèle du tarif D_4 (0,518 ¢/m^3)[56].

[141] Ne pouvant pas présumer du futur profil de consommation de l'ensemble de la clientèle consommant du GAC, Gaz Métro propose d'établir le tarif d'équilibrage de ces clients à la moyenne entre le prix pour un profil de consommation parfaitement stable (0,00 ¢/m^3) et le prix pour un profil de consommation moyen de l'ensemble de la clientèle du tarif D_4 et de réviser ce tarif, sur cette base, à chaque dossier tarifaire.

[142] **La Régie approuve la méthode d'établissement du tarif d'équilibrage pour les clients consommant du GAC proposée par Gaz Métro.**

4.1.5 SUIVI DES MARCHÉS RÉGIONAUX

[143] L'ACIG, dans sa preuve, souligne l'importance que revêtent à ses yeux les prix du gaz naturel dans la région du nord-est américain.

56 Pièce B-0197, page 69.

« *Il devient donc important de suivre l'évolution des prix dans les marchés régionaux et à Iroquois. Cette comparaison des prix se fait en termes d'un différentiel de lieu par rapport au prix de référence en Amérique du Nord qui est le prix NYMEX. Le prix livré à GMi EDA doit lui aussi être cité en termes de prix NYMEX.*

La Régie devrait encourager Gaz Métro à inclure ce type d'information dans son plan d'approvisionnement gazier. Cette information serait un indicateur de l'effet de certains changements sur la dynamique régionale de marché[57]. »

[144] Gaz Métro invoque deux arguments pour ne pas fournir les informations demandées par l'ACIG sur les prix régionaux du gaz naturel dans le nord-est américain :

- ces informations ne sont pas pertinentes;
- des clauses de confidentialité empêchent la publication de certaines données.

[145] Compte tenu de l'ensemble des changements au contexte du gaz naturel touchant le nord-est américain, la Régie considère qu'il serait hasardeux d'affirmer que les prix du gaz naturel à divers points dans le nord-est américain ne sont pas pertinents pour le plan d'approvisionnement. Ces comparaisons de prix se font généralement sur la base des prix NYMEX[58] ajustés pour un différentiel de lieu.

[146] La Régie considère que les orientations touchant les plans d'approvisionnement de Gaz Métro sont stratégiques et ne doivent pas être limitées par des questions techniques, comme, par exemple, la confidentialité des banques de données sur des prix de marché.

[147] **La Régie ordonne, par conséquent, à Gaz Métro de prendre les mesures requises pour que les informations touchant les prix du gaz naturel dans le nord-est américain puissent être divulguées dans le cadre de la revue annuelle du plan d'approvisionnement.**

57 Pièce C-ACIG-0013, page 5.
58 New York Mercantile Exchange (NYMEX).

4.1.6 SUIVIS DIVERS

[148] La Régie prend acte des suivis suivants déposés par le distributeur :

- comparaison des prévisions des ventes avec les données réelles (volumes normalisés) (décision D-2008-140[59]);
- comparaison des prévisions de la journée de pointe avec les données réelles (décision D-2008-140);
- prévision de la journée de pointe en utilisant 39 DJ et des conditions moyennes de vent à cette température (décision D-2010-144).

4.2 APPROBATION DES COÛTS ASSOCIÉS À L'ACTIVITÉ DE VENTE DE GNL

[149] Dans la décision D-2010-144[60], la Régie demandait à Gaz Métro de présenter, lors du prochain dossier tarifaire, une description détaillée des méthodes d'établissement des coûts utilisés pour chacun des éléments énoncés à la décision D-2010-057[61], tant en mode prévisionnel qu'en mode réel, au moment de l'examen du rapport annuel.

[150] Dans cette même décision, la Régie établissait certains principes relatifs à l'évaluation des coûts de fourniture, compression, transport, équilibrage et distribution (F, C, T, E et D) à allouer aux clients GNL.

[151] Dans la décision D-2011-030[62], la Régie précisait plusieurs règles régissant l'évaluation des coûts relatifs à l'utilisation de l'usine LSR[63] et au maintien de la fiabilité pour la clientèle de l'activité règlementée.

[152] Dans le cadre du présent dossier, Gaz Métro présente les méthodes d'établissement des coûts reliés à l'approvisionnement du client GNL et l'évaluation de ces coûts pour l'année tarifaire 2012.

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[59] Dossier R-3662-2008 Phase 2.
[60] Décision D-2010-144, dossier R-3720-2010 Phase 2, page 50.
[61] Décision D-2010-057, dossier R-3727-2010, page 9.
[62] Dossier R-3751-2010.
[63] Liquéfaction, stockage et regazéification (LSR).

4.2.1 MÉTHODES D'ÉTABLISSEMENT DES COÛTS

Coûts reliés à l'utilisation de l'usine LSR

[153] Le distributeur calcule la portion des coûts d'entreposage et de liquéfaction à allouer au client GNL en tenant compte des pertes par évaporation. Il répartit les pertes par évaporation au prorata de la capacité d'entreposage réservée pour les clients réguliers et le client GNL.

[154] Tenant compte de l'évaporation, Gaz Métro évalue que les coûts d'utilisation de l'usine LSR à allouer au client GNL sont de 179 000 $[64] pour un volume total de GNL de 2 $10^6 m^3$ prévu pour 2012.

[155] **La Régie approuve les coûts d'utilisation de l'usine LSR de 179 000 $ à allouer au client GNL pour l'année 2012.**

Coûts reliés aux composantes F, C, T, E, D et au Fonds vert

[156] Le distributeur calcule le coût de chacune des composantes F, C, T, E et D, conformément à la décision D-2010-144, à partir des coûts unitaires moyens établis au présent dossier.

[157] Pour les composantes E et D, il retient le coût unitaire moyen d'un client ayant un profil de consommation similaire à celui de l'usine LSR dans son ensemble. Pour 2012, ce profil correspond à un client au palier 5.8, volet A du tarif D_5.

[158] Gaz Métro établit le coût du service du Fonds vert en appliquant le tarif du Fonds vert du distributeur établi au dossier tarifaire 2012.

[159] **La Régie approuve la méthode d'établissement des coûts liés aux composantes fourniture, compression, transport, équilibrage, distribution et au Fonds vert.**

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[64] Pièce B-0031, page 16.

4.2.2 TRAITEMENT DU DOSSIER TARIFAIRE 2012

[160] Gaz Métro indique avoir ajusté son revenu requis de façon à considérer la projection du remboursement de l'ensemble des coûts attribués à Gaz Métro Solution Transport (GMST) pour l'année 2012. Elle précise que le revenu requis ajusté servira à l'établissement des tarifs pour l'année 2012.

[161] Gaz Métro mentionne également avoir ajusté son revenu plafond en ajoutant un facteur exogène équivalent aux coûts de distribution attribués à GMST et avoir ajusté l'exogène relatif au Fonds vert afin de refléter la portion du coût de service attribué à GMST.

[162] **La Régie juge ce traitement conforme à ses décisions passées[65].**

4.2.3 COÛT DE MAINTIEN DE LA FIABILITÉ

[163] Dans la décision D-2011-030, la Régie prévoyait que Gaz Métro devait appliquer un coût de maintien de la fiabilité aux ventes de GNL à GMST. Elle avait demandé que ce coût soit basé sur le coût des outils de transport à acquérir avant le début de l'année pour maintenir la fiabilité des ventes du distributeur en cas d'hiver extrême. En effet, la totalité de la provision additionnelle requise pour assurer les ventes de Gaz Métro en cas d'hiver extrême est acquise de cette façon.

[164] Gaz Métro propose une option applicable seulement aux ventes de GNL à GMST. Cette dernière s'engagerait à rembourser les coûts reliés aux outils d'approvisionnement seulement s'il s'avérait dans les faits qu'ils étaient requis, c'est-à-dire après la fin de l'année, seulement si l'hiver extrême se matérialisait. GMST n'aurait donc pas à payer un coût de maintien de la fiabilité si aucun coût additionnel n'était encouru.

[165] En audience, Gaz Métro indique qu'elle n'envisage pas étendre cette façon de procéder à la clientèle des services réglementés. Les arguments invoqués par Gaz Métro sont les suivants :

65 Décision D-2010-057, dossier R-3727-2010; décision D-2010-144, dossier R-3720-2010 Phase 2; décision D-2011-030, dossier R-3751-2010.

- si l'hiver extrême se matérialise et qu'il s'avère impossible de se procurer sur le marché au cours de cet hiver les outils requis pour répondre aux besoins, les conséquences pour les clients de Gaz Métro et le réseau seraient catastrophiques;
- la situation de GMST est différente, les clients de GMST pourraient, le cas échéant, être interrompus puisqu'ils ont des solutions de rechange comme, par exemple, des camions utilisant du diesel.

[166] L'audience permet cependant de faire ressortir qu'au moment de la constatation de l'hiver extrême, des livraisons de GNL à GMST auraient déjà été effectuées à même le réservoir de GNL servant à garantir la fiabilité des ventes réglementées du distributeur. En effet, la constatation d'un hiver extrême prend un certain temps et les livraisons à GMST se dérouleraient normalement dans l'intervalle. Par conséquent, si jamais les outils d'approvisionnement ne sont pas disponibles sur le marché, la clientèle des services réglementés du distributeur serait à risque.

[167] Confrontée à ce scénario, Gaz Métro indique que la disponibilité des outils d'approvisionnement sur le marché n'est qu'une question de prix et que GMST est prête à payer des sommes considérables.

> « *Solutions Transport va avoir une absolue obligation de nous le rembourser, ils vont être prêts à payer, peu importe ce que ça coûte. Et ce n'est pas tout le monde dans le marché qui est prêt à payer n'importe quel prix*[66]. »

[168] La FCEI affirme que si c'est possible pour GMST, ce devrait l'être également pour la clientèle des services réglementés.

[169] La Régie constate que, si des situations où il n'y a pas d'outils disponibles sur le marché sont possibles, la proposition de Gaz Métro sur le maintien de la fiabilité comporte des risques pour la clientèle des services réglementés et le réseau, qui ont d'ailleurs été amplement décrits par Gaz Métro. Dans un tel contexte, la Régie ne peut accepter la proposition de Gaz Métro.

[170] Par ailleurs, si la philosophie qui prévaut est que les outils sont toujours disponibles et qu'il ne s'agit que d'une question de prix, la Régie considère qu'il devrait

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[66] Pièce A-0040, page 51.

alors être possible pour la clientèle des services réglementés de bénéficier du même traitement. Dans ce contexte, la Régie ne peut non plus accepter la proposition de Gaz Métro.

[171] **La Régie rejette la proposition de Gaz Métro et établit le coût de la fiabilité pour GMST selon la décision D-2011-030.**

[172] La Régie invite le distributeur à lui soumettre, dans le cadre d'un dossier tarifaire ultérieur, un rapport qui traiterait spécifiquement de la question de la fiabilité globale des ventes du distributeur en cas d'hiver d'extrême et de la possibilité d'acquérir, au besoin seulement, une partie ou l'ensemble des outils requis pour assurer cette fiabilité. Toute proposition découlant de ce rapport devra accorder le même traitement à la clientèle des services réglementés et à GMST.

[173] Conformément à la décision D-2011-030[67], pour l'année 2011-2012, le distributeur détermine qu'il devra faire un achat supplémentaire de 26 10^3m^3/jour de transport FTSH sur la période d'hiver pour compenser la vente de GNL et maintenir la sécurité d'approvisionnement de sa clientèle régulière. Il évalue le coût de cet approvisionnement additionnel à 100 000 $ en considérant le tarif de transport FTSH de TCPL à 100 % de CU[68] (2,489 ¢/m^3)[69].

[174] **La Régie approuve le coût de maintien de la fiabilité de 100 000 $ pour l'année 2012.**

4.3 TAUX DE RENDEMENT

4.3.1 CADRE JURIDIQUE

[175] En vertu de l'article 31 de la Loi, la Régie réglemente les activités de distribution de gaz naturel au Québec, dont celles pour lesquelles Gaz Métro détient un droit exclusif.

[67] Décision D-2011-030, dossier R-3751-2010, page 14.
[68] Coefficient d'utilisation (CU).
[69] Pièce B-0031, page 10.

[176] Diverses dispositions de la Loi encadrent l'exercice de la fixation d'un taux de rendement par la Régie. Lorsqu'elle fixe un tarif de gaz naturel, ce dernier doit être juste et raisonnable [article 49 (7)]. Le tarif qu'elle fixe doit permettre l'atteinte, par le distributeur, d'un rendement raisonnable sur la base de tarification [article 49 (3)]. De plus, la Régie doit procéder à cet exercice en s'assurant du respect des ratios financiers [article 49 (5)]. Les tarifs ne doivent toutefois pas prévoir des taux plus élevés ou des conditions plus onéreuses qu'il n'est nécessaire pour permettre, notamment, de couvrir les coûts de capital et d'exploitation, de maintenir la stabilité du distributeur et le développement normal de son réseau de distribution ou d'assurer un rendement raisonnable sur la base de tarification (article 51).

[177] Dans le cadre du présent dossier, la norme du rendement raisonnable et les critères utilisés pour l'établir n'ont fait l'objet d'aucun débat. Dans sa décision D-2009-156[70], la Régie précisait son rôle et ses pouvoirs lorsqu'elle fixe un taux de rendement pour un distributeur. Après avoir passé en revue la jurisprudence élaborée au cours des ans par les tribunaux supérieurs canadiens et américains, la Régie rappelait les trois critères qui ont été historiquement reconnus par les régulateurs comme base pour l'établissement de la norme du rendement raisonnable, soit les critères de l'investissement comparable, de l'intégrité financière et de l'attraction des capitaux.

[178] Selon ces trois critères, pour être raisonnable, un taux de rendement sur le capital doit :

- être comparable à celui que rapporterait le capital investi dans une autre entreprise présentant un risque analogue (critère de l'investissement comparable);
- permettre à l'entreprise d'attirer des capitaux additionnels à des conditions raisonnables (critère de l'effet d'attraction de capitaux);
- permettre à l'entreprise réglementée de préserver son intégrité financière (critère de l'intégrité financière).

[179] Dans sa décision D-2009-156, la Régie concluait que ces critères font consensus et qu'ils peuvent servir de guide dans l'exercice de sa juridiction à l'égard de la fixation d'un taux de rendement raisonnable.

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70 Dossier R-3690-2009.

[180] Par ailleurs, dans cette même décision, la Régie considérait que son devoir était de déterminer un taux de rendement raisonnable et que la méthode qu'elle utilisait relevait de sa discrétion. À cet égard, la Régie rappelait que les tribunaux ont reconnu la grande latitude et la discrétion des organismes de régulation dans le choix de la meilleure méthode pour fixer un taux de rendement raisonnable sur l'avoir de l'actionnaire.

4.3.2 TAUX DE RENDEMENT

4.3.2.1 Modèles utilisés pour établir le coût de l'avoir propre

[181] Les experts entendus lors de l'audience utilisent des approches et des modèles différents pour estimer le taux de rendement sur l'avoir de l'actionnaire de Gaz Métro.

[182] L'expert retenu par Gaz Métro, le Dr Morin, utilise le modèle d'évaluation des actifs financier (MÉAF), le modèle empirique d'évaluation des actifs financiers (MEÉAF), le modèle d'actualisation des flux monétaires (AFM), l'historique de la prime de risque des sociétés réglementées à partir des rendements réalisés d'indices américains et l'historique de la prime de risque des sociétés réglementées à partir des rendements autorisés américains. Pour sa part, l'expert retenu par l'ACIG, le Dr Booth, utilise le MÉAF. Il valide l'estimation obtenue à l'aide du modèle AFM[71]. Ce dernier porte sur l'ensemble du marché canadien et non sur un titre en particulier.

[183] Le MÉAF est représenté par l'équation suivante :

$$K = R_f + \beta^*(R_m - R_f)$$

[184] Cette équation représente le taux de rendement (K) qu'un investisseur s'attend à recevoir d'un placement effectué sur un titre comportant un certain risque. Le rendement attendu pour ce titre (K) correspond au rendement qui pourrait être obtenu par un investissement sans risque (R_f), auquel est ajoutée une prime de risque. Cette prime, propre au titre évalué, est proportionnelle au risque du marché (R_m - R_f). Ce dernier est estimé par la différence entre le rendement généré par un portefeuille de titres diversifié (R_m) et celui d'un investissement sans risque (R_f). La relation entre le risque du marché et le risque associé au titre est exprimée par le facteur bêta (β).

71 Pièce C-ACIG-0015, page 66.

[185] Le taux de rendement sur l'avoir de l'actionnaire résultant des calculs du D^r^ Booth en vertu du MÉAF se situe dans une fourchette allant de 6,75 % à 7,80 %, avant la prise en compte des frais d'émission, de l'ajustement pour le risque de Gaz Métro et des écarts de crédit entre les rendements des obligations à long terme des sociétés réglementées canadiennes et ceux des obligations du gouvernement. Après la prise en compte de ces éléments, le D^r^ Booth recommande, pour Gaz Métro, un taux de rendement autorisé sur l'avoir de l'actionnaire de 8,1 %, soit le point-milieu de sa fourchette allant de 7,5 % à 8,7 %.

[186] Le taux de rendement sur l'avoir de l'actionnaire résultant des calculs du D^r^ Morin en vertu du MÉAF est de 9,09 %, avant la prise en compte des frais d'émission et de l'ajustement pour le risque de Gaz Métro.

[187] Le MEÉAF est représenté par l'équation suivante :

$$K = \alpha + R_f + \beta^*(R_m - R_f - \alpha)$$

[188] Le MEÉAF vise à corriger le biais à la baisse découlant du MÉAF pour les compagnies présentant un bêta inférieur à l'unité. Dans la littérature spécialisée, ce biais est constaté dans des recherches qui utilisent comme estimateur du taux sans risque le rendement de 30 jours des bons du trésor (T-Bills) de 90 jours. La correction obtenue par l'introduction d'un facteur alpha (α) dans l'équation du MEÉAF se traduit par une hausse de l'ordonnée à l'origine et une réduction de la pente de la relation linéaire.

[189] Selon l'expert de l'ACIG, la correction pour ce biais n'est plus justifiée lorsqu'on utilise, comme estimateur du taux sans risque, les rendements des obligations de long terme des gouvernements. De plus, il qualifie le MEÉAF du D^r^ Morin de modèle d'ajustement à double bêta[72] lorsque celui-ci utilise le MEÉAF et des bêta ajustés. Il indique que les résultats empiriques ne justifient pas l'utilisation des bêta ajustés dans le MEÉAF.

[190] L'expert de Gaz Métro, est en désaccord avec cette position et soutient que l'utilisation des rendements d'obligations de long terme ne corrige qu'en partie le biais en question[73].

72 Pièce C-ACIG-0015, page 46.
73 Pièce B-0058, page 42.

[191] Le D^{r} Morin utilise le modèle AFM pour estimer le taux de rendement sur l'avoir de l'actionnaire de Gaz Métro. Le D^{r} Booth utilise ce modèle uniquement aux fins de validation des résultats produits par le MÉAF pour l'ensemble du marché canadien. Ce modèle indique que le prix (P) d'une action est égal à la valeur actualisée au taux (k) de ses dividendes futurs qui croissent indéfiniment au taux (g).

[192] Le modèle AFM s'exprime donc par l'équation :

$$P = D_1/(k-g)$$

ou, écrit d'une autre façon

$$k = D_1 /P + g$$

où

k = taux de rendement sur l'avoir de l'actionnaire
D_1 = dividende versé à l'année 1
P = prix au marché de l'action
g = taux de croissance des dividendes

[193] Le D^{r} Morin utilise le modèle AFM à partir des prévisions d'analystes financiers, pour différents indices américains. Selon le D^{r} Morin, les résultats de l'application du modèle AFM pour les sociétés réglementées canadiennes serait probablement peu fiable. En effet, il explique qu'il y a peu de sociétés canadiennes réglementées, qu'il y a eu beaucoup de changements de propriétaire et beaucoup de restructurations corporatives, que leurs titres sont peu transigés, qu'il y a peu de comparables avec un historique de données financières homogènes et, finalement, qu'il est difficile d'obtenir un estimateur fiable du taux de croissance des dividendes étant donné que les analystes financiers ne produisent pas de prévisions de croissance pour les sociétés réglementées canadiennes[74].

[74] Pièce B-0058, page 52.

[194] Le D[r] Morin présente la prévision des analystes financiers pour la croissance viable à l'infini, pour différents indices américains :

- modèle AFM - Natural Gas Utilities Value Line Growth – 4,6 %;
- modèle AFM - Natural Gas Utilities Zacks Growth – 4,7 %;
- modèle AFM - Combination Gas & Elec Utilities Value Line Growth – 6,9 %;
- modèle AFM - Combination Gas & Elec Utilities Zacks Growth – 5,8 %.

[195] À partir de ces estimations de croissance, il présente des estimations de rendements des sociétés réglementées américaines pour différents indices américains avant toute prise en compte de frais d'émission et d'un ajustement pour le risque spécifique d'une société :

- modèle AFM - Natural Gas Utilities Value Line Growth – 8,6 %;
- modèle AFM - Natural Gas Utilities Zacks Growth – 8,6 %;
- modèle AFM - Combination Gas & Elec Utilities Value Line Growth – 10,8 %;
- modèle AFM - Combination Gas & Elec Utilities Zacks Growth – 10,3 %.

[196] Le D[r] Morin utilise également les rendements réalisés de l'indice Standard & Poor's *S&P utility* pour la période 1930-2010, afin de calculer une prime de risque historique. Celui-ci est constitué de sociétés réglementées américaines de l'industrie du gaz naturel et de l'électricité. À partir du rendement annuel de cet indice, il soustrait annuellement les revenus d'intérêts des obligations à long terme du gouvernement américain en excluant le gain ou la perte en capital, afin de calculer la prime de risque pour la période. Par la suite, il additionne cette prime de risque à sa prévision du taux de rendement des obligations de 30 ans du gouvernement du Canada pour l'année 2012, qu'il établit à 4,4 %. Il refait le même exercice à partir de l'indice *Moody Natural Gas* pour la période de 1955-2001.

[197] Le taux de rendement sur l'avoir de l'actionnaire résultant des calculs du D[r] Morin est de 9,9 % pour l'indice *S&P utility* et 10,1 % pour l'indice *Moody Natural Gas*, avant toute prise en compte de frais d'émission et d'un ajustement pour le risque spécifique d'une société.

[198] Enfin, le Dr Morin calcule une prime de risque implicite pour les sociétés réglementées américaines à partir de près de 600 décisions de régulateurs américains sur le taux de rendement couvrant la période de 1986 à 2010. Il calcule cette prime de risque entre les rendements autorisés par les régulateurs américains et les rendements des obligations américaines à long terme en excluant le gain ou la perte en capital. Par la suite, il additionne cette prime de risque à sa prévision du taux de rendement des obligations de 30 ans du gouvernement du Canada pour l'année 2012, qu'il établit à 4,4 %. Les frais d'émissions sont inclus dans la prime étant donné qu'ils sont inclus dans les rendements autorisés des régulateurs américains.

[199] Dans ce dernier cas, le taux de rendement sur l'avoir de l'actionnaire résultant des calculs du Dr Morin est de 10,6 %, incluant les frais d'émission mais avant toute prise en compte d'un ajustement pour le risque spécifique d'une société.

[200] La Régie a déjà statué sur le MEÉAF[75]. Elle est d'avis qu'il n'y a pas de nouveaux éléments pouvant la mener à reconsidérer ce modèle.

[201] Quant au modèle reposant sur l'historique de la prime de risque des sociétés réglementées à partir des rendements réalisés d'indices américains, la Régie constate que les rendements des indices *S&P utility* et *Moody Natural Gas* sont calculés à partir des rendements réalisés des sociétés de gestion américaines. Ces dernières peuvent inclure autant des actifs réglementés que non réglementés.

[202] Par ailleurs, la Régie s'interroge sur le résultat produit par ce modèle. En effet, la Régie constate un écart important entre le résultat de 5,5 % à 5,7 % pour la prime de risque calculée à partir de ces indices, alors que dans l'application du MÉAF présentée par le Dr Morin, cette prime de risque est de 4,7 % sur la base d'une prime de risque du marché de 6,7 % et d'un bêta de 0,70. En utilisant ce même bêta et les primes de risque de 5,5 % à 5,7 % découlant des indices américains *S&P utility* et *Moody Natural Gas*, on en déduit une prime de risque de marché de l'ordre de 7,8 % à 8,1 %. La Régie juge que ces primes de risque de marché ne reflètent pas la réalité historique observée.

[203] Pour ce qui est du modèle s'appuyant sur l'historique de la prime de risque des sociétés réglementées à partir des rendements autorisés américains, la Régie souligne la

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75 Décision D-2003-93, dossier R-3492-2002, page 71.

circularité de cet exercice. Lors de l'audience, le D[r] Morin indique ce qui suit au sujet de la circularité[76] :

> « *R. Votre question soulève des points très intéressants en matière de réglementation. C'est le fameux argument de circularité. Si on se regarde dans des miroirs, il n'y a jamais rien qui va changer. L'économie pourrait s'effondrer puis si tout le monde a le même taux de rendement comme si on se regarde dans des miroirs.*
>
> *Alors, l'expert financier ce qu'il fait pour essayer de contourner cette difficulté de circularité c'est qu'il va examiner des données de marché, des bêtas, des cours boursiers, des méthodes MÉAF, méthode AFM qui, elles, minimisent cet élément de circularité. Vous avez sans doute remarqué dans mon témoignage que je fais rarement et même jamais référence à ce que les autres régulateurs ont fait en matière de taux de rendement parce que ça devient circulaire. Alors, l'on l'évite cette circularité-là en s'appuyant sur des données de marché.* »

[204] Quant au modèle AFM, la Régie est d'avis que ce modèle comporte certaines difficultés pratiques, notamment quant à l'estimation du taux de croissance des dividendes des titres choisis. La Régie note que l'estimation du taux de croissance des dividendes est prospective et qu'elle repose sur les prévisions des analystes financiers. La Régie note également que l'application de ce modèle se fait à partir de données américaines uniquement.

[205] **En regard de la preuve soumise, la Régie retient principalement aux fins de sa décision le MÉAF.** Il s'agit de l'approche retenue dans ses décisions antérieures. Ce modèle est reconnu et utilisé tant dans les milieux de la finance que par la majorité des experts témoignant devant les organismes de réglementation.

[206] L'utilisation de ce modèle comporte cependant des difficultés que la Régie aborde plus en détail dans les sections suivantes.

[207] Par mesure de prudence, comme aucun modèle ne peut reproduire parfaitement, à lui seul, les attentes de rendement des investisseurs, la Régie prend en considération, aux fins de son appréciation du taux de rendement sur l'avoir de l'actionnaire de Gaz Métro, les résultats du modèle AFM, malgré les faiblesses mentionnées précédemment.

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76 Pièce A-0051, pages 159 et 160.

TAUX SANS RISQUE

[208] Le MÉAF requiert l'établissement d'un taux sans risque (R_f) auquel s'ajoute la prime de risque de l'entreprise. Selon la pratique usuelle, le taux sans risque utilisé est celui des obligations de long terme de 30 ans du gouvernement du Canada.

[209] Le Dr Morin propose un taux sans risque de 4,40 %[77] pour l'application du MÉAF, tandis que le Dr Booth propose un taux sans risque de 4,50 %[78].

[210] Enfin, le taux sans risque découlant du Consensus Forecasts du mois d'août 2011 et de l'écart entre le rendement des obligations du gouvernement du Canada de 10 ans et de 30 ans pour le mois précédent, tel que déposé par Gaz Métro, se situe à 3,91 %[79].

[211] **Sur la base de la preuve au dossier, la Régie établit le taux sans risque dans une fourchette variant de 3,91 % à 4,50 %.**

PRIME DE RISQUE DU MARCHÉ

[212] Le MÉAF requiert l'établissement de la prime de risque du marché ($R_m – R_f$) en fonction de laquelle est fixée la prime de risque d'un distributeur repère.

[213] Le Dr Morin présente une prime de risque du marché de 6,70 % à partir d'études sur la base de données historiques ou sur la base de données prévisionnelles[80]. Les dates de début et de fin des données historiques varient d'une étude à l'autre.

[214] Le Dr Booth présente des estimations de la prime de risque du marché à partir de séries de données couvrant des périodes débutant en 1926 et en 1957 et se terminant en 2010[81]. Il établit ses estimations à partir des moyennes arithmétique et géométrique et de la méthode des moindres carrés ordinaires. Il recommande une prime de risque du marché de 5,5 %. Sa recommandation est corroborée par une étude du professeur

77 Pièce B-0058, pages 22 à 25.
78 Pièce C-ACIG-0015, pages 31 à 33.
79 Pièce B-0304.
80 Pièce B-0273, page 17.
81 Pièce C-ACIG-0017, pages 14, 15 et 26.

Fernandez. Les résultats de cette étude sont établis à partir des opinions d'un échantillon de professeurs de finance, d'analystes financiers et de dirigeants de sociétés[82].

[215] La Régie souligne qu'elle a statué dans le passé sur l'établissement de la prime de risque de marché à partir de moyennes arithmétiques des données historiques ainsi que sur les sources de données pour établir cette prime de risque de marché[83]. La Régie décide de faire porter son appréciation sur les données historiques à partir d'études autant canadiennes qu'américaines qui lui donnent accès à des données fiables et mises à jour de façon régulière.

[216] La Régie maintient l'établissement de la prime de risque du marché sur la base de la moyenne arithmétique des rendements observés sur les marchés. Le choix des périodes de référence pour établir la prime de risque soulève cependant certains enjeux. En effet, la moyenne calculée peut différer sensiblement selon l'année de départ et de fin et la série de données retenues. Dans ce contexte, la Régie choisit d'accorder une prépondérance aux moyennes de longues périodes.

[217] La Régie souligne également que dans sa décision D-2009-156[84], aux fins d'estimer la prime de risque du marché, elle utilisait des proportions égales pour les données canadiennes et américaines. La Régie utilise la même approche en tenant compte de la preuve au présent dossier.

[218] **Sur la base de la preuve au dossier, la Régie établit la prime de risque du marché dans une fourchette variant de 5,50 % à 5,75 %.**

RISQUE D'UN DISTRIBUTEUR REPÈRE

[219] Aux fins d'application du principe d'isolement, la Régie définit le distributeur repère comme étant une société de service public dont 100 % des activités sont réglementées et présentant un niveau de risque faible. Ce risque est mesuré par le facteur bêta. Celui-ci représente le différentiel de risque entre la société repère et le marché en général.

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82 Pièce C-ACIG-0015, page 52.
83 Décision D-2003-93, dossier R-3492-2002, pages 73 et 74.
84 Décision D-2009-156, dossier R-3690-2009, page 62.

[220] L'établissement du bêta constitue l'une des difficultés les plus importantes dans l'application du MÉAF. Ces difficultés ont trait tant à l'établissement d'un échantillon de référence représentatif du risque des sociétés réglementées permettant de définir le distributeur repère qu'à l'obtention de séries de données valables pour procéder à une estimation robuste.

[221] Le D[r] Morin présente un bêta ajusté de 0,70 calculé à partir de différents indices canadiens et américains. Il motive l'utilisation de ces bêta ajustés sur le fait qu'ils sont publiés et accessibles aux investisseurs.

[222] Le D[r] Booth présente diverses estimations basées sur les données récentes, mais souligne qu'il est nécessaire de faire preuve de jugement et propose d'établir le bêta d'une firme repère sur la base de la moyenne historique des bêta des sociétés réglementées qu'il évalue entre 0,45 et 0,55. Le D[r] Booth utilise des bêta bruts pour le calcul de ces estimations. Il indique que les bêta bruts sont publiés par des maisons de courtage comme celle de la Banque Royale[85].

[223] Le D[r] Morin utilise des bêta ajustés pour tenir compte des recherches empiriques montrant la tendance des bêta à converger vers un. Le D[r] Booth soutient plutôt que les sociétés réglementées étant habituellement des sociétés moins risquées, leurs bêta convergent vers la moyenne des bêta de leur groupe et non vers un qui correspond à la moyenne des bêta de l'ensemble des sociétés du marché.

[224] En ce qui a trait à l'utilisation de bêta ajustés, la Régie retient la conclusion qu'elle a déjà exprimée dans ses décisions antérieures[86]. L'explication couramment utilisée dans les milieux de la recherche financière pour justifier un ajustement des bêta bruts, soit la tendance observée sur le plan empirique pour les bêta en général d'évoluer à terme vers la moyenne du marché qui est de un, ne peut être valablement retenue dans le cas d'une entreprise réglementée. En présence de droits exclusifs de distribution, il apparaît difficile de concevoir comment le risque propre à cette activité pourrait se modifier substantiellement à la hausse et évoluer vers le risque du marché au fil des ans.

[225] Ceci ne résout toutefois pas nécessairement de façon entière la problématique reliée à la qualité des bêta bruts et à leur capacité à prédire correctement les rendements

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85 Pièce C-ACIG-0075.

86 Décision D-2010-147, dossier R-3724-2010; décision D-2009-156, dossier R-3690-2009; décision D-2007-116, dossier R-3630-2007; décision D-2003-93, dossier R-3492-2002.

dans le cadre de l’application du MÉAF. Il demeure difficile de déduire la valeur du bêta de façon objective à partir des données observées sur les marchés pour les sociétés retenues dans les échantillons. **En conséquence, sur la base de la preuve au dossier, la Régie établit le bêta d’un distributeur repère dans une fourchette de 0,50 à 0,60.**

RISQUE DE GAZ MÉTRO

[226] Le risque d’affaires du distributeur a fait l’objet d’un examen en profondeur en 2007 et 2009. Sur la base de la preuve au dossier, la Régie refait, en 2011, l’examen de ce risque.

[227] Le D^r^ Morin évalue qu’un ajustement de 40 points de base à la hausse est justifié par le différentiel des bêta ajustés, le différentiel d’avoir propre requis selon le pointage du risque d’affaires évalué par *S&P utility* et son jugement informé d’expert[87]. Il attribue ce risque supérieur à la composition de la clientèle et à la position concurrentielle par rapport aux autres formes d’énergie.

[228] De plus, le D^r^ Morin indique qu’il y a deux façons d’ajuster le risque supérieur de Gaz Métro, soit par un taux de rendement plus élevé ou par un ratio de capitalisation plus élevé ou un levier financier moins élevée. Le D^r^ Morin indique que ces 40 points de base sont équivalents à une augmentation de 4 % d’avoir propre selon des études théoriques et empiriques[88].

[229] Gaz Métro demande d’augmenter de 4 % le niveau d’avoir propre pour le faire passer de 38,5 % à 42,5 % et de diminuer de 7,5 % à 3,5 % les actions privilégiées. Le D^r^ Morin présente une recommandation différente qu’il explique ainsi[89] :

> « *Q.80 WHAT BUSINESS RISK AND FINANCIAL RISK PROFILE HAS S&P CURRENTLY ASSIGNED TO GMLP?*
>
> *A. S&P classifies GMLP as having “excellent” business risk and “significant” financial risk. This profile indicates an implied rating of A-, that is, low single A, based on the table above. Based on this profile, the debt ratio guideline is 45%-50%, that is, an equity ratio of 50%-55%. GMLP’s equity ratio of 46% (common 38.5% plus preferred 7.5%) places the company outside those*

[87] Pièce B-0058, page 64.
[88] Pièce B-0058, page 77.
[89] Pièce B-0058, pages 75 et 76.

> *guidelines. My recommended common equity ratio in the range of 40%-45%, or 47.5% - 52.5% inclusive of preferred equity, would place the Company close to the bottom end of the S&P debt targets.* » [nous soulignons]

[230] Selon le D^r^ Booth, le risque de Gaz Métro a baissé depuis la dernière décision de la Régie en 2009[90]. Selon l'expert, le développement des gaz de schiste est un changement important qui se traduit par une augmentation de l'offre. De plus, il indique que la baisse du prix du gaz naturel a augmenté sa compétitivité par rapport au pétrole et à l'électricité.

[231] Le D^r^ Booth mentionne que Gaz Métro est plus risquée que ses pairs, en termes de risque d'affaires, en raison de la composition de sa clientèle. Il souligne, cependant, qu'un ratio de capitalisation plus élevé et une couverture plus étendue des risques assurée par la présence de nombreux comptes de frais reportés viennent contrebalancer ce risque d'affaires plus élevé.

[232] Selon la Régie, le risque pour l'investisseur correspond à l'incertitude liée, sur un horizon de placement, à la réalisation du rendement sur son capital ainsi qu'à la récupération de son capital.

[233] La Régie constate que l'historique de rendements réalisés montre la constance de Gaz Métro à réaliser son rendement autorisé[91]. La Régie constate également que la compétitivité du gaz naturel, face aux autres sources d'énergie, s'est améliorée depuis 2009[92].

[234] Selon la Régie, les détenteurs d'obligations et de parts de Gaz Métro ont, par rapport au contexte de 2009, des perspectives très semblables en ce qui à trait au risque à long terme. Dans les rapports des agences de crédit, on ne retrouve pas de constat quant à la matérialisation du risque de ne pas récupérer le capital pour les activités réglementées au Québec[93].

[235] La Régie considère le risque global de l'entreprise supérieur à celui du distributeur repère, notamment en raison de la composition de sa clientèle et de la concurrence de

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90 Pièce C-ACIG-0015, page 2.
91 Pièce B-0178, Gaz Métro-7, document 12.5, page 3.
92 Pièce B-0178, Gaz Métro-7, document 12.2.
93 Pièce B-0308, pages 7 et 8.

l'électricité au Québec. Cependant, elle tient compte dans son appréciation de la structure de capital présumée de Gaz Métro, soit 38,5 % d'avoir propre et 7,5 % d'actions privilégiées, qui est supérieure à celle du distributeur repère, ainsi que de la couverture plus étendue de ces mêmes risques par des comptes de frais reportés.

[236] La Régie juge que le risque de l'entreprise ne s'est pas modifié significativement depuis la décision D-2009-156, bien qu'il soit toujours supérieur à celui d'un distributeur repère. **Sur la base de la preuve au dossier, la Régie considère que le risque plus élevé justifie le maintien d'un ajustement à la hausse par rapport à la prime de risque d'un distributeur repère de l'ordre de 25 à 35 points de base.**

[237] **La Régie considère également que le risque supérieur à celui d'un distributeur repère est compensé par sa structure de capital présumée. La Régie maintient la structure de capital présumée de 38,5 % d'avoir propre, de 7,5 % d'actions privilégiées et de 54 % de dette.**

FRAIS D'ÉMISSION ET AUTRES COÛTS D'ACCÈS AU MARCHÉ DES CAPITAUX

[238] En 2009, les frais d'émissions ont fait l'objet d'un examen détaillé qui reposait sur une évaluation des coûts d'émission réels depuis 1993, tels que fournis par Gaz Métro.

[239] Le Dr Morin recommande 30 points de base pour ces frais.

[240] Le Dr Booth recommande 50 points de base pour ces frais. Il soutient qu'un tel ajustement est compatible avec la pratique appliquée par plusieurs régulateurs.

[241] **Sur la base de la preuve au dossier, la Régie établit une fourchette de la provision pour frais d'émission et autres frais d'accès aux marchés des capitaux de 30 à 40 points de base, en accordant un poids plus élevé au bas de cette fourchette.**

RÉSULTATS DES AUTRES MODÈLES

[242] Selon la Régie, le MÉAF demeure le modèle de référence le plus approprié pour servir de guide dans la détermination d'un taux de rendement raisonnable sur l'avoir de l'actionnaire.

[243] Cependant, il est aussi admis par tous les experts qu'aucun modèle ne peut, à lui seul, représenter correctement les attentes des investisseurs dans toutes les circonstances et dans toutes les phases des cycles économiques et financiers. En conséquence, la Régie juge nécessaire de prendre en considération les résultats produits par le modèle AFM, malgré les faiblesses mentionnées plus haut.

[244] Par ailleurs, la Régie rappelle que, dans sa décision D-2007-116[94], elle mentionnait que l'application du MÉAF présentait une difficulté particulière lorsque la détermination du rendement dans un dossier intervient dans une période où les taux courants des obligations gouvernementales s'écartent de façon significative du taux moyen de longue période. La prime de risque étant calculée sur de longues périodes et représentant la différence entre la moyenne arithmétique des rendements du marché et de ceux des obligations gouvernementales, cette prime est donc représentative des conditions qui prévalent sur cette même période. La Régie concluait qu'un ajustement s'imposait lorsque les conditions du marché obligataire s'éloignent de cette moyenne.

[245] **Compte tenu de la preuve au présent dossier et des remarques émises dans sa décision D-2007-116, la Régie juge qu'un ajustement de l'ordre de 25 à 50 points de base par rapport aux résultats du MÉAF est justifié dans les circonstances.**

COMPARAISON AVEC LES DISTRIBUTEURS CANADIENS

[246] Dans le cadre du présent dossier, Gaz Métro a produit une preuve sur la comparaison des rendements autorisés et des structures de capitaux présumées des distributeurs canadiens[95].

[247] En réponse à une demande de renseignements, Gaz Métro explique les éléments importants qui ont changé depuis la décision D-2009-156 et qui ont un impact significatif aux fins de la détermination du taux de rendement.

> « *Depuis la décision D-2009-156, les autres distributeurs canadiens ont vu leur taux de rendement et leur structure de capital évoluer et s'ajuster à la hausse de façon plus marquée que Gaz Métro.*

94 Dossier R-3630-2007.
95 Pièce B-0057.

De plus, dans le cadre du dossier EB-2009-0084, l'Ontario Energy Board a remis à niveau le taux de rendement pour mettre en place une nouvelle formule d'ajustement automatique qui prévoit un taux de 9,66 % en 2011. Gaz Métro prévoit donc une augmentation des rendements des distributeurs repères en raison des taux qui seront octroyés à Enbridge Gas Distribution et Union Gas à compter de 2012[96]. »

[248] La Régie examine, ci-après, la preuve présentée par Gaz Métro. Elle rappelle cependant le risque de circularité que cet exercice comporte, tel qu'exprimé par le D^r^ Morin[97].

Structure de capital

[249] La Régie constate que la comparaison des structures de capital présentée par Gaz Métro exclut les actions privilégiées[98]. En réponse à une demande de renseignements, Gaz Métro produit un tableau[99] indiquant la portion d'actions privilégiées dans la structure de capital des distributeurs comparables qu'elle a identifiés. La Régie souligne que lorsque l'on considère à la fois les actions ordinaires et les actions privilégiées de Gaz Métro, cette dernière est le distributeur ayant le moins de dette dans sa structure de capital présumée, si on exclut Western Division de la société Pacific Northern Gas Ltd.

[250] Gaz Métro indique que si on augmentait la proportion de dette de 54 % à 57,5 %, le risque financier augmenterait vraisemblablement[100].

[251] Le D^r^ Morin explique, dans une réponse à une demande de renseignements[101], les effets d'un ratio de dette élevé dans une structure de capital :

« *All else remaining constant* […] *The results of empirical studies and theoretical studies indicate that equity costs increase from 7.6 to 13.8 basis points per one percentage point increase in the debt ratio. The more recent studies indicate that the upper end of that range is more indicative of the effect on equity costs.* »

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96 Pièce B-0178, Gaz Métro-7, document 12.2, page 1.
97 Pièce A-0051, pages 159 et 160.
98 Pièce B-0057, page 7.
99 Pièce B-0181, page 22.
100 Pièce A-0051, page 18.
101 Pièce B-0178, Gaz Métro-7, document 12.1, page7.

[252] Selon le D[r] Morin, une cote de crédit A est celle qui minimise les coûts de financement[102]. Or, la Régie constate que Gaz Métro a une cote de crédit A stable, selon l'agence de notation *S&P utility*, avec un ratio d'environ 70 % de dette dans sa structure de capital réelle. La Régie estime que la cote de crédit et les informations contenues dans le rapport de *S&P utility*, notamment sur les activités réglementées de distribution de gaz naturel au Québec, sont des informations pertinentes que le marché utilise dans l'évaluation du risque de Gaz Métro, comme le D[r] Morin l'exprime[103].

[253] Dans sa preuve, le D[r] Morin indique que pour obtenir une cote de crédit A selon les paramètres de S&P, le ratio de dette doit être entre 45 % et 50 %. Il indique également que le ratio de capitaux propres de Gaz Métro devrait se situer entre 40 % et 45 % et entre 47,5 % et 52,5 %, lorsqu'on y inclut les actions privilégiées[104].

[254] La Régie conclut qu'aucun des comparables canadiens identifiées par Gaz Métro ne respecte les paramètres de *S&P utility*.

[255] Dans son argumentation, l'ACIG mentionne ce qui suit en ce qui a trait au ratio de dette des comparables :

> « *Pour les fins de son analyse, M. Cabana fait également défaut de tenir compte du niveau élevé d'avoir privilégié dans la structure de capital présumé de Gaz Métro. La preuve démontre que, contrairement à Gaz Métro, les sociétés Atco Gas, Terasen Gas, Enbridge Gas et Union Gas ne disposent d'aucun avoir privilégié dans leur structure de capital présumée pour fins réglementaires, ce qui a évidemment pour effet d'augmenter considérablement le poids de leur dette par rapport à Gaz Métro. Ainsi,* […] *on apprend que pour les années 2010 et 2011, les composantes dette dans la structure de capital présumée de ces sociétés étaient les suivantes :*
>
> - *ATCO Gas 61,0 %*
> - *Terasen Gas 60,0 %*
> - *Enbridge Gas 64,00 %*
> - *Union Gas 64,00 %*

102 Pièce B-0058, page 71.
103 Pièce A-0051, pages 159 et 160.
104 Pièce B-0058, pages 75 et 76.

> *On ne saurait sous-estimer l'importance que comporte ces niveaux de dettes plus élevés dans l'appréciation du risque financier de ces sociétés aux yeux de la communauté des investisseurs*[105]. »

[256] À propos des actions privilégiées, le Dr Booth mentionne :

> « *In the case of Gaz Metro, the 7.5% preferred share component is deemed and does not represent an increase in financial risk to the common shareholder. That is, there are no preferred share dividends that have to be paid prior to a dividend to the common shareholder. To all intents and purposes, Gaz Metro has a 46% common equity component at a cost equal to a weighted average of its allowed ROE and preferred share cost. In Dr. Booth's judgment, the additional 10% common equity component over Union and EGDI offsets Gaz Metros' higher business risk so that also allowing a higher ROE amounts to double counting. Consequently Dr. Booth does not recommend a premium to his estimate of a fair ROE for a benchmark utility*[106]. » [nous soulignons]

[257] La Régie détermine que Gaz Métro, avec 54 % de dette présumée, a nettement moins de dette dans sa structure de capital présumée que ses comparables, ce qui reflète son risque supérieur à celui d'un distributeur repère.

Taux de rendement

[258] Gaz Métro utilise le résultat produit par la formule de l'Ontario Energy Board (OEB), en application depuis 2010 pour les distributeurs d'électricité, pour calculer les rendements autorisés d'Enbridge Gas Distribution Inc. (Enbridge) et de Union Gas, pour 2010 et 2011. Or, il n'est pas acquis que cette formule s'appliquera à Enbridge et Union Gas. Par ailleurs, la Régie constate que la durée du mécanisme incitatif d'Enbridge est de cinq ans, soit de 2008 à 2012 avec une possibilité d'extension jusqu'en 2014[107]. Tel que confirmé en audience, les rendements autorisés pour Enbridge et Union Gas, pour 2010 et 2011, sont plutôt de 8,39 % et 8,54 % respectivement[108]. Ainsi, la Régie juge que, dans sa comparaison, Gaz Métro anticipe les décisions de l'OEB relatives aux taux de rendement autorisés pour Enbridge et Union Gas.

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105 Pièce C-ACIG-0084, page 15.
106 Pièce C-ACIG-0022, pages 5 et 6.
107 C-FCEI-0034, page 25.
108 Pièce A-0057, pages 188 et 189.

[259] Gaz Métro reproduit sa comparaison[109] en utilisant les rendements autorisés d'Enbridge et de Union Gas. De plus, elle retire de son échantillon la société Fortis BC, étant donné que cette entreprise est un distributeur d'électricité. Enfin, elle justifie la taille de son échantillon de sociétés canadiennes ainsi : sur une base statistique, un régulateur ne pourrait établir un taux de rendement à l'aide d'un échantillon de quelques sociétés[110].

[260] En audience, Gaz Métro indique que pour les fins de comparaison, on ne devrait pas utiliser un taux de rendement autorisé qui n'a pas été mis à jour depuis cinq ans.

[261] La Régie constate que dans le cadre du dossier R-3690-2009, l'expert de Gaz Métro, le D^r Carpenter, avait utilisé, aux fins de comparaison, des taux de rendement autorisés par les régulateurs américains provenant de décisions remontant aussi loin que l'année 1999[111]. La Régie est d'avis que pour servir de comparaison, c'est le taux de rendement autorisé tiré de la dernière décision disponible qui doit être utilisé.

[262] Gaz Métro ajoute que les rendements réalisés par Enbridge et Union Gas ont été substantiellement plus élevés que les rendements autorisés[112].

[263] Le D^r Morin indique que le sujet des rendements réalisés dépasse le cadre de sa preuve[113].

[264] Le D^r Booth, pour sa part, émet plusieurs commentaires sur l'échantillon de comparables présentés par Gaz Métro. Il ne comprend pas pourquoi on inclut un distributeur d'électricité, soit Fortis BC, sans inclure les autres. Il indique que les sociétés P&G, Alta Gas, Gazifère, P&G Western, P&G Fort St. John, P&G Tumbler Ridge ne sont pas de bons comparables, étant donné qu'elles sont des petites sociétés. Il indique également que les comparables adéquats de Gaz Métro sont plutôt ATCO Gas, Terasen Gas, Union Gas et Enbridge[114].

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109 Pièce B-0306.
110 Pièce B-0309, page 57.
111 Dossier R-3690-2009, pièce B-28.
112 Pièce A-0057, pages 175 et 176.
113 Pièce B-0178, Gaz Métro-7, document 12.5, page 3.
114 Pièce A-0051, pages 265 à 271.

[265] À partir des distributeurs comparables identifiés par le Dr Booth, la FCEI produit une comparaison des taux de rendement autorisés de ces sociétés sur la période de 2004 à 2011. Le tableau indique que Gaz Métro a un rendement supérieur à la moyenne de ces sociétés[115].

[266] La Régie est d'avis qu'il est préférable d'avoir un échantillon de plusieurs sociétés comparables. Cependant, elle considère que l'inclusion ou non de sociétés dans un échantillon aux fins d'appréciation de comparaison doit prendre en compte, notamment, la taille du marché, le niveau de risque, le cadre réglementaire, etc.

[267] En conclusion de cet exercice de comparaison avec des distributeurs canadiens, la Régie constate que Gaz Métro se positionne favorablement, en tenant compte de la structure de capital présumée et du taux de rendement autorisé.

COMPARAISON AVEC LES DISTRIBUTEURS AMÉRICAINS

[268] En audience, il a été question de la comparaison entre les rendements octroyés aux entreprises réglementées canadiennes et ceux octroyés à leurs vis-à-vis américaines. Tant les dirigeants et experts de Gaz Métro que ceux de l'ACIG sont venus exposer devant la Régie les enjeux qui s'y rapportent.

[269] Selon la Régie, la preuve présentée à cet égard au présent dossier n'est pas très différente de celle dont elle a été saisie en 2009. La Régie est d'avis que la preuve soumise ne lui permet pas d'en arriver à des conclusions différentes de celles auxquelles elle était arrivée en 2009.

[270] La Régie juge que, bien qu'il soit manifeste que les taux de rendement octroyés aux États-Unis soient supérieurs en moyenne à ceux octroyés au Canada, la preuve est peu concluante quant aux raisons qui justifieraient de retenir les taux accordés aux États-Unis comme base de référence pour les taux à accorder au Québec. La preuve est, en effet, très faible quant aux données récentes sur les décisions américaines et quant à l'analyse des régimes réglementaire et institutionnel en vigueur chez nos voisins. Entre autres, le distributeur n'a pas fait la démonstration que les opportunités qui s'offrent sur le marché américain sont comparables en termes de risque.

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115 Pièce C-FCEI-0038, page 7.

[271] La Régie constate que la preuve du Dr Morin inclut des rendements réalisés calculés à partir de données consolidées. Le Dr Morin n'a pas calculé les rendements réalisés pour la partie réglementée uniquement des sociétés de son échantillon, étant donné qu'il ne possède pas cette information[116]. La Régie juge pertinentes ces informations. Elle juge également pertinente, aux fins de son appréciation, la comparaison, sur une longue période, entre les rendements autorisés et les rendements réalisés pour la partie des activités de distribution de gaz naturel des sociétés réglementées américaines de risque comparable.

[272] La preuve présentée ne permet donc pas à la Régie de conclure quant à la comparabilité des contextes réglementaire, institutionnel, économique et financier des deux pays et de leurs impacts sur les opportunités qui en découlent pour les investisseurs et pour les sociétés à tarifs réglementés.

4.3.3 FORMULE D'AJUSTEMENT AUTOMATIQUE (FAA)

4.3.3.1 Preuve de l'experte McShane dans le cadre du dossier R-3724-2010

[273] Lors de son plaidoyer sur le taux de rendement, le procureur de Gaz Métro a soulevé l'irrecevabilité et l'illégalité de la mise en preuve, par le Dr Booth, du contenu du témoignage de l'experte McShane dans le cadre du dossier R-3724-2010 relatif à Gazifère.

> « *Et au paragraphe 267, je vous dis ceci. Cette volonté du témoin Booth de contrer le modèle "94 McShane", c'est comme ça qu'il l'a appelé dans son rapport lui-même, des deux côtés de l'Outaouais constitue un exercice qui est inutile parce que la Régie n'est pas saisie de la preuve versée au dossier de Gazifère et deuxièmement c'est un exercice qui est malheureusement irrecevable en droit parce que madame McShane n'est pas devant vous pour défendre sa formule.*
>
> *Le docteur Booth a oublié de répondre au docteur Morin. Il s'est malheureusement employé à dire que la preuve de madame McShane est irrecevable. Mais il s'est trompé de dossier parce que la preuve de madame McShane n'est pas devant vous. Donc, tout son témoignage est irrecevable parce que, malheureusement, vous n'avez pas l'autre côté de la médaille.*

[116] Pièce B-0178, Gaz Métro-7, document 12.5, page 3.

Si vous vouliez écouter le témoignage de monsieur Booth qui tente de crucifier littéralement madame McShane, bien, il faudrait avoir la preuve de madame McShane qui, sauf erreur, et maître Sarault pourra peut-être me le confirmer, n'est pas au dossier de la Régie. Et madame McShane n'est pas là devant vous pour répondre. Parce que Gaz Métro ne l'a pas embauchée parce que... bien, je ne le sais pas pourquoi, mais Gaz Métro ne l'a pas embauchée. Je dis ça comme ça, puis je n'ai aucune idée. Mais il ne l'a pas embauchée. Elle a eu beaucoup de succès en Ontario, par contre, madame McShane. Je n'aurais pas dû dire ça, moi. Je sens que je ne connais pas toute l'histoire. Mais tout ce que je veux vous dire, Monsieur le Président, c'est que de deux choses l'une, ou bien on ajourne, on fait venir madame McShane et on nous donne la possibilité de répondre aux arguments de monsieur Booth, ou bien, malheureusement pour lui, la preuve de monsieur Booth est irrecevable. Pourquoi? Parce qu'il répond à une preuve qui n'est pas au dossier et on n'a pas la possibilité d'y répondre en l'absence de madame McShane.

C'est un peu juridique, là, mais c'est le genre d'affaire qui cause problème à un moment donné. Alors, malheureusement pour le docteur Booth, et je le soumets, la Régie ne peut pas retenir comme recevable cette preuve en l'absence de la preuve de madame McShane, parce que, malheureusement, vous n'avez qu'un côté de la médaille[117]. »

[274] La Régie ne retient pas ces prétentions. Tout d'abord, la Régie considère que les commentaires du procureur de Gaz Métro sont de la nature d'une objection à la preuve formulée tardivement. Gaz Métro ne s'est nullement objectée à cette preuve en cours d'audience. Ce n'est que lors de son plaidoyer, une fois la preuve close, de part et d'autre, qu'elle soulève l'illégalité. Une telle objection, non formulée en temps opportun, mais lors du plaidoyer, ne peut être accueillie.

[275] En référant au témoignage de M^{me} McShane, l'expert de l'ACIG ne faisait que rapporter les paramètres d'un débat scientifique ayant cours chez les régulateurs canadiens depuis plusieurs années quant à la meilleure méthode à utiliser pour fixer un taux de rendement raisonnable, en d'autres mots, du ouï-dire. À cet effet, il est depuis fort longtemps reconnu qu'un expert devant témoigner devant un tribunal puisse recourir au ouï-dire, ce qu'a fait l'expert de l'ACIG en rapportant la position de M^{me} McShane. La Cour d'appel s'est prononcée sur la question de la façon suivante :

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[117] Pièce A-0061, pages 250 à 252.

> « *Now, expert witnesses, in giving opinions within their fields of expertise, are entitled to base these opinions on second-hand evidence and this will not affect the admissibility of their opinions although it may affect their weight or probative value*[118]. »

[276] **La Régie juge que Gaz Métro, en acceptant subsidiairement que la formule adoptée par la Régie dans la décision D-2010-147, la « formule Gazifère », lui soit appliquée pour l'année témoin 2012, donnait ouverture à l'expert de l'ACIG de recourir à la preuve ayant menée à l'adoption de cette formule, d'autant plus qu'aucune objection n'a été formulée à cet égard.**

[277] Enfin, le procureur de Gaz Métro insiste sur le fait que le D^r^ Booth n'a pas répondu au bon expert en répondant à M^me^ McShane, alors qu'il aurait dû s'employer à répondre au D^r^ Morin. Est-ce vraiment le cas? Un expert doit-il nécessairement répondre à un autre dans le cadre d'un dossier tarifaire? La Régie ne le croit pas.

[278] Lorsqu'elle procède à la fixation des tarifs, la Régie effectue un vaste exercice de consultation auprès de tous les participants, y incluant le distributeur. Il ne s'agit pas d'un litige faisant l'objet d'un débat contradictoire, mais plutôt d'un travail d'inquisition par lequel la Régie se doit d'obtenir toute l'information nécessaire pour lui permettre d'établir un taux de rendement raisonnable. Dans un tel contexte, il est souhaitable qu'un expert fasse valoir son opinion, indépendamment de celles des autres experts au dossier, sans avoir à leur répondre spécifiquement.

4.3.3.2 Formule d'ajustement retenue

[279] À la suite d'une demande de la Régie, Gaz Métro dépose le calcul du taux de rendement sur l'avoir de l'actionnaire pour 2012 résultant de l'application de la formule d'ajustement actuelle et de l'ajustement de 25 à 55 points de base, pour tenir compte de l'effet de la crise financière, retenu pour les années tarifaires 2010 et 2011. Ce taux de rendement s'établit, après avoir soustrait l'ajustement de 55 ou 25 points pour les années 2010 et 2011, dans une fourchette de 8,36 % à 8,66 %[119].

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118 *Paillé* c. *Lorcon Inc*., [1985] C.A. 528.
119 Pièce B-0304.

[280] Le Dr Morin recommande une nouvelle formule d'ajustement du taux de rendement pour tenir compte des écarts de crédit corporatif et d'une sensibilité moindre du coût de l'avoir propre aux variations des rendements des obligations du gouvernement. Le Dr Morin recommande également que cette formule soit révisée aux trois ans.

[281] Le Dr Morin présente deux analyses au soutien de sa conclusion selon laquelle la sensibilité du coût de l'avoir propre aux variations des taux de rendement des obligations à long terme du gouvernement est plus petite que le facteur 0,75 de la présente formule.

[282] Dans la première analyse, le Dr Morin fait une régression entre la prime de risque implicite des sociétés réglementées américaines, à partir de près de 600 décisions de régulateurs américains sur le taux de rendement, et les rendements des obligations américaines à long terme pour la période de 1986 à 2010.

[283] Dans la deuxième analyse, le Dr Morin, fait une régression entre la prime de risque implicite des sociétés réglementées canadiennes, à partir de 31 décisions de l'Office national de l'énergie (ONÉ) sur le taux de rendement de 1980 à 1994, et les rendements des obligations à long terme du gouvernement canadien.

[284] À partir de ces résultats, le Dr Morin recommande la formule d'ajustement suivante, soit qu'à partir de la deuxième année, le taux de rendement serait égal :

- au taux de rendement initial;
- plus 50 % de la variation du taux de rendement des obligations de 30 ans du gouvernement du Canada par rapport à celui fixé initialement;
- plus 50 % de la variation du taux de rendement des obligations à long terme de l'ensemble des sociétés canadiennes réglementées de cote A, par rapport à celui fixé initialement.

[285] Le Dr Booth recommande l'application de la formule adoptée par la Régie pour Gazifère[120]. Il précise que le facteur de 0,50 pour tenir compte des écarts de crédit lui semble excessif. Il le conserve cependant, en précisant que sur la durée d'un cycle

[120] Décision D-2010-147, dossier R-3724-2010, annexe 1.

économique complet, l'effet est neutre. Selon un rapport de la Banque du Canada, le facteur d'ajustement dû aux changements des écarts de rendement des obligations corporatives relié au risque de défaut, qui peut être lié à un changement du coût de l'avoir propre, serait de l'ordre de 37 %[121].

[286] À partir de cette formule, le Dr Booth compare le taux de rendement sur l'avoir propre, selon sa formule, avec les rendements autorisés par l'ONÉ de 1995 à 2011.

[287] Selon le Dr Booth, avec un facteur d'ajustement de 50 % de la variation du taux de rendement des obligations de 30 ans du gouvernement du Canada, tel que proposé par le Dr Morin, les taux de rendement produits par cette formule sont supérieurs aux taux de rendement autorisés par l'ONÉ de 1995 à 2011. Selon le Dr Booth, cela implique qu'aucun régulateur canadien n'aurait autorisé des rendements raisonnables durant cette période. Par ailleurs, il rappelle que pendant la même période, les régulateurs canadiens ont refait l'exercice plus d'une fois, sur la base de preuves d'experts.

[288] Enfin, le Dr Booth considère que l'économie canadienne a récupéré de la dernière récession, mais que les problèmes reliés à la dette de pays souverains ont des impacts sur la situation économique mondiale. Il estime que les écarts de crédit sont supérieurs à ce qu'ils devraient être dans un cycle économique normal. Il recommande un ajustement de 25 à 40 points de base pour les effets liés aux écarts de crédit.

[289] La Régie retient le point de vue du Dr Booth selon lequel les écarts de crédit sont encore supérieurs à ce qu'ils devraient être dans un cycle économique normal. Compte tenu de la preuve au dossier et de l'objectif de maintenir un accès au marché à des conditions raisonnables, la Régie juge qu'il y a lieu d'octroyer, dans les circonstances du présent dossier, un ajustement pour tenir compte des écarts de crédit.

[290] **Par conséquent, la Régie établit, pour tenir compte des écarts de crédit, une fourchette variant de 25 à 40 points de base.**

[291] La Régie est d'avis que la formule qu'elle a retenue pour Gazifère permet de faire fluctuer adéquatement le taux de rendement autorisé en fonction de la variation du taux

[121] Pièce C-ACIG-0015, page 77.

de rendement des obligations de 30 ans des sociétés réglementées canadiennes, tout en tenant compte des écarts de crédit auxquels est soumise Gaz Métro.

[292] La Régie considère que la formule qu'elle a retenue pour Gazifère aurait permis, malgré une volatilité accrue des rendements autorisés, d'établir des rendements autorisés mieux adaptés durant la crise financière. **La Régie conclut qu'il y a lieu, pour établir le taux de rendement de Gaz Métro à compter de l'année tarifaire 2013, de remplacer la formule actuelle par celle qu'elle a retenue pour Gazifère.**

[293] **La Régie estime que, pour l'année tarifaire 2013 et les années subséquentes, l'ajustement pour les écarts de crédit est pris en compte par le deuxième membre de la nouvelle FAA.** Ainsi, dans l'éventualité où les écarts de crédit demeurent élevés, l'ajustement sera maintenu. À l'inverse, si les écarts de crédit reviennent à leur normale, l'ajustement diminuera.

[294] La Régie est d'avis que les écarts de rendement des obligations des sociétés réglementées de cote A ne réagissent pas de la même façon que les écarts de rendement des obligations des sociétés non réglementées de cote A pendant les cycles économiques, particulièrement pendant une crise financière. **La Régie retient l'indice C29530Y de Bloomberg comme estimateur des écarts de crédit des sociétés réglementées canadiennes. Pour les prochains dossiers tarifaires, la Régie demande donc à Gaz Métro de fournir les données de Bloomberg du mois de juillet aux fins de l'application de la nouvelle formule.**

[295] En audience, le D^r Booth indique que l'indice Bloomberg est respectivement pour juillet et août de 1,44 % et 1,51 %[122]. **La Régie retient la valeur de 1,5 % de l'indice Bloomberg aux fins de l'application de la nouvelle formule.**

[296] **La Régie fixe également, aux fins de l'application de la nouvelle formule, le taux sans risque à 4,0 %.**

[297] Ainsi, le taux de rendement sur l'avoir de l'actionnaire pour l'année tarifaire 2013 et les années subséquentes sera calculé selon la formule présentée à l'annexe 2.

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122 Pièce C-ACIG-0083.

[298] La Régie précise que le taux de rendement sur l'avoir de l'actionnaire résultant de l'application de cette formule devra être exprimé en pourcentage arrondi à deux décimales.

4.3.3.3 Période d'application de la FAA

[299] Lors de son plaidoyer[123], le procureur d'OC, s'appuyant sur des décisions de l'OEB et du témoignage de l'expert Booth, soumet que les demandes répétitives de Gaz Métro pour modifier la FAA, trois fois dans les derniers cinq ans, vont à l'encontre des bienfaits, sur le plan de l'efficacité et de l'efficience règlementaire, de l'application d'une FAA. De plus, l'intervenante est préoccupée par les coûts liés à ces demandes. Ces coûts étant supportés par la clientèle, il n'y aurait aucun incitatif pour Gaz Métro de freiner ses demandes. L'intervenante assimile la stratégie de Gaz Métro à cet égard à de la « règlementation par l'usure ». Sur ce point, OC reçoit l'appui d'autres intervenants, notamment l'ACIG et l'UMQ.

[300] Lors de sa réplique[124], le procureur de Gaz Métro soumet que la Régie a le devoir de s'assurer que le taux de rendement est raisonnable à chaque année. Gaz Métro soutient que cette année, elle s'est présentée devant la Régie sur cet enjeu parce qu'elle n'avait pas le choix. Compte tenu de la durée limitée à deux ans de l'ajustement pour tenir compte de l'effet de la crise économique, il y avait une invitation à revenir pour discuter de l'ajustement de la FAA. Gaz Métro ajoute que la présente formule, qui était la même que Gazifère avant la décision D-2010-147[125], n'est plus applicable puisque la situation a évolué depuis 2009 et que les marchés connaissent une période de très forte volatilité.

[301] Gaz Métro assimile la demande d'OC et de l'ACIG de limiter sa capacité à revoir les modes d'ajustement de son taux de rendement comme bon lui semble, comme une mise en demeure, voire une clause punitive manifestement illégale, contraire aux principes établis dans la Loi.

[302] Selon Gaz Métro, il s'agit là d'une approche de tarification qui n'est pas sérieuse ni raisonnable.

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[123] Pièce A-0059, pages 112 à 118.

[124] Pièce A-0063, pages 203 à 208.

[125] Dossier R-3724-2000 Phases 2 et 4.

[303] D'abord, la Régie tient à rappeler que Gaz Métro a, au cours des dernières années, présenté une preuve à l'appui de diverses méthodes d'établissement du taux de rendement. Au dossier R-3630-2007, elle a proposé l'utilisation de la méthode Fama-French. Dans le cadre du dossier R-3662-2008, elle a proposé que la Régie n'applique pas la FAA et augmente les frais d'émission. Au dossier R-3690-2009, elle a proposé l'utilisation de l'ATWACC[126], soutenant que la FAA était brisée. Finalement, au présent dossier, Gaz Métro demande que la Régie ajuste son taux de rendement et sa structure de capital présumée et qu'elle modifie la FAA. Gaz Métro s'est adressée à la Régie quatre fois durant les cinq dernières années pour une révision de son taux de rendement.

[304] Contrairement à ce que plaide le procureur d'OC, les demandes de Gaz Métro ne visaient pas nécessairement à modifier la FAA, mais visaient plutôt la recherche de la méthode appropriée pour établir un taux de rendement raisonnable. Tout en reconnaissant que Gaz Métro a droit à un taux de rendement raisonnable, la Régie est préoccupée par ses demandes répétitives et les coûts règlementaires qui y sont associés.

[305] Sans vouloir empêcher Gaz Métro de présenter une demande en matière de taux de rendement si la situation le requiert, la Régie juge que l'efficacité, l'efficience et la stabilité du processus règlementaire militent en faveur d'une période d'application d'une FAA suffisamment longue avant de réviser ses paramètres ou encore, avant de revoir la méthode d'établissement du taux de rendement. **C'est pourquoi la Régie approuve l'application de la nouvelle FAA pour une période de trois ans à compter du dossier tarifaire 2013.**

[306] Au terme de cette période, Gaz Métro pourra, si elle le souhaite, demander à ce que la Régie revoie les paramètres de la FAA ou encore, demander une révision de son taux de rendement. La Régie considère cette période raisonnable, compte tenu du degré de sophistication de la formule retenue ainsi que de l'importance des charges réglementaires assumées par la clientèle de Gaz Métro depuis 2007.

RÉSULTATS DE L'ANALYSE

[307] La Régie présente ci-dessous un tableau résumant les valeurs retenues pour chacun des paramètres.

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[126] *After tax weighted average cost of capital* (ATWACC).

TABLEAU 4
Valeur retenue pour chacun des paramètres

Paramètres	**Bas de la fourchette**	**Haut de la fourchette**
Taux sans risque	3,91 %	4,50 %
Prime de risque de marché	5,50 %	5,75 %
Bêta d'un distributeur repère	0,50	0,60
Ajustement pour le risque de Gaz Métro	0,25 %	0,35 %
Frais d'émissions	0,30 %	0,40 %
Sous total n^{o} 1 : Résultat produit par le MÉAF	**7,21 %**	**8,70 %**
Ajustement pour tenir compte des résultats des autres modèles	0,25 %	0,50 %
Sous total n^{o} 2 : Taux de rendement de l'avoir propre avant ajustement pour tenir compte des écarts de crédit	**7,46 %**	**9,20 %**
Ajustement pour tenir compte des écarts de crédit	0,25 %	0,40 %
Total : Taux de rendement de l'avoir propre après ajustement pour tenir compte des écarts de crédit	**7,71 %**	**9,60 %**

[308] Ainsi, en tenant compte de l'ensemble des conclusions précédentes, le taux de rendement raisonnable à autoriser pour le distributeur se situe dans une fourchette allant de 7,71 % à 9,60 %.

4.3.3.4 Conclusion

[309] **Sur la base de la preuve au dossier et pour l'ensemble des motifs exprimés précédemment, la Régie fixe, pour l'année tarifaire 2012, le taux rendement sur l'avoir de l'actionnaire de Gaz Métro à 8,90 %. La Régie maintient la structure de capital présumée de 38,5 % d'avoir propre, 7,5 % d'actions privilégiées et de 54 % de dette.**

[310] **À partir de l'année tarifaire 2013 et pour les années subséquentes, la Régie retient la FAA décrite à l'annexe 2 de la présente décision. La Régie fixe la période d'application de la nouvelle formule à trois ans à compter de l'année tarifaire 2013.**

[311] **Sur la base d'un taux sans risque de 4,0 %, le taux de rendement autorisé de Gaz Métro correspond à une prime de risque implicite de 4,90 %. De plus, sur la base de la structure de capital retenue, du taux de rendement sur l'avoir propre de 8,90 %, du taux de rendement des actions privilégiées et du coût de la dette présentés au dossier[127], la Régie estime à 7,50 % le coût en capital moyen sur la base de tarification et à 6,37 %[128] le coût en capital prospectif.**

4.4 STRATÉGIE TARIFAIRE

4.4.1 DÉMONSTRATION QUANTITATIVE DE L'ALLOCATION DU COÛT DE SERVICE

[312] Dans sa décision D-2010-144, la Régie autorisait la tenue de deux réunions techniques visant à permettre à Gaz Métro de faire une démonstration quantitative de la méthode d'allocation du coût de service. Des rencontres avec les intervenants ont eu lieu les 21 février et 18 mars 2011[129]. Lors de ces rencontres, auxquelles le personnel technique de la Régie a assisté, Gaz Métro fait une démonstration quantitative des méthodes d'allocation des coûts et présente les liens entre les coûts et les tarifs.

[313] À la pièce B-0354, Gaz Métro dépose un rapport faisant état, notamment, des objectifs et principes qui guident l'allocation des coûts ainsi que de la démonstration quantitative de cette allocation et proposant des pistes de réflexion et d'ajustement à cet égard.

[314] L'objectif principal de l'allocation des coûts est de répartir les coûts de l'année témoin entre les différents services et catégories de clients de la façon la plus équitable et raisonnable possible, en fonction des liens de causalité. Gaz Métro réfère à l'ordonnance G-429[130] de 1985 portant sur les principes d'allocation des coûts et indique que, malgré le fait que plusieurs critères relatifs à l'évaluation des facteurs d'allocation aient été analysés et reconsidérés depuis cette ordonnance, la priorité est encore accordée, le plus possible, à la relation de cause à effet.

127 Pièce-B-0048, page 1.
128 Pièce-B-0232.
129 Pièce B-0354, page 4.
130 Régie du gaz et de l'électricité, dossier R-3028-85.

[315] Gaz Métro présente chacune des étapes de l'allocation des coûts et aborde la question de l'allocation des conduites principales. Le distributeur procède aussi à une analyse de sensibilité et conclut que la plus grande part de ses coûts est allouée selon un facteur direct ou mixte qui respecte le principe de causalité des coûts.

[316] **La Régie est satisfaite de la démonstration quantitative de la méthode d'allocation des coûts et déclare que celle-ci répond au suivi requis.**

4.4.2 PISTES DE RÉFLEXION ET D'AJUSTEMENT PROPOSÉES

[317] À la suite de la démonstration quantitative de l'allocation des coûts, 11 pistes de réflexion sont identifiées. Ce sont les suivantes :

- mise à jour du document de référence sur les méthodes et calculs des facteurs d'allocation;
- impact de l'abolition du tarif D_M sur l'étude d'allocation des coûts;
- ajout de l'étape de classification dans le tableau de fonctionnalisation;
- réflexion sur l'allocation des conduites principales;
- facteur d'allocation CDA[131];
- réflexion sur l'établissement des demandes quotidiennes maximales;
- impact du raccordement de clients producteurs sur les méthodes d'allocation des coûts;
- analyse du poste « Dépenses d'administration »;
- révision des facteurs « revenus » dans l'allocation;
- dépenses d'informatique;
- impact des normes IFRS[132].

[318] En réponse à une question de TCE, Gaz Métro indique qu'elle est disposée à inclure la méthode de répartition des coûts du PGEÉ à la liste des pistes de réflexion

131 Facteur d'allocation des autres frais de comptabilité des abonnés.
132 *International Financial Reporting Standards* (IFRS).

présentée au tableau 1.3 du Rapport sur l'allocation des coûts, les liens entre les coûts et les tarifs ainsi que la vision tarifaire de Gaz Métro en distribution[133].

[319] **La Régie prend acte des pistes de réflexion et d'ajustement proposées en lien avec l'étude d'allocation des coûts. Elle demande à Gaz Métro de présenter des recommandations découlant de cette réflexion lors du dossier tarifaire 2014. De plus la Régie demande qu'un suivi soit fait sur le travail en cours lors du dossier tarifaire 2013.**

4.4.3 RÉALISATION D'UNE ÉTUDE D'ALLOCATION DES COÛTS AUX DEUX ANS

[320] Afin de faciliter le travail de réflexion envisagé, Gaz Métro propose de produire l'allocation des coûts à tous les deux ans, plutôt qu'annuellement.

[321] Une année sur deux serait dédiée à la réflexion sur les ajustements envisagés. Le cas échéant, des modifications seraient présentées ainsi que l'impact de celles-ci sur l'allocation des coûts de l'année précédente. Gaz Métro demande que cette proposition s'applique dès le prochain dossier tarifaire. Ainsi, la prochaine étude des coûts serait présentée lors du dossier tarifaire 2014 et porterait sur le budget 2012-2013.

[322] La Régie estime important de permettre à Gaz Métro de poursuivre la réflexion entamée en ce qui a trait à la question de l'allocation des coûts et d'explorer les pistes d'ajustement identifiées. Par ailleurs, elle considère que le contexte actuel du marché gazier, incluant la mise en place éventuelle de producteurs de gaz naturel au Québec, n'est pas propice à un changement permanent de la régularité de la production de l'étude de l'allocation des coûts.

[323] **La Régie autorise Gaz Métro à reporter la réalisation de l'étude d'allocation des coûts d'une année, soit jusqu'au dossier tarifaire 2014. À ce moment, la demande du distributeur de ne produire l'étude qu'aux deux ans pourra être resoumise et, le cas échéant, réévaluée.**

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[133] Pièce B-0156, page 47; pièce B-0157, pages 23 à 35, tableau XIII; pièce B-0068, pages 26 et 27, tableau 1.3; pièce B-0194, pages 1 et 2.

4.4.4 CORRECTION DU NIVEAU D'INTERFINANCEMENT

[324] Dans le cadre du présent dossier, Gaz Métro propose de corriger le niveau d'interfinancement entre les petits et les grands clients du tarif D_1. Considérant la situation concurrentielle, les impacts tarifaires sur la facture totale et le maintien du développement rentable du marché résidentiel, le distributeur propose donc une augmentation de 2 % des revenus générés au premier palier du tarif (0 – 10 950 m^3) compensée par une baisse aux autres paliers du tarif D_1.

[325] Gaz Métro explique que le niveau d'interfinancement du premier palier du tarif D_1, qui se situe actuellement à 41 %[134], est préoccupant. Elle ajoute que la Régie avait indiqué partager cette préoccupation dans la décision D-2010-144.

[326] Dans la décision D-2010-144, la Régie avait rejeté une proposition du Groupe de travail de corriger l'interfinancement au premier palier du tarif D_1, compte tenu qu'une correction des frais de base était en cours.

[327] Le distributeur indique que la correction aux frais de base, dont la dernière tranche est intégrée aux tarifs cette année, ne change pas le niveau d'interfinancement au premier palier du tarif D_1 dans son ensemble (0 – 10 950 m^3). Il note que l'augmentation des frais de base réduit le niveau d'interfinancement des plus petits clients de ce palier (0 - 1 095 m^3).

[328] Gaz Métro affirme que l'augmentation des frais de base n'a pas eu d'impact tarifaire significatif pour les clients consommant entre 1 095 et 3 650m^3 et que, comme le développement du marché résidentiel se situe majoritairement dans cet intervalle volumétrique, cette augmentation n'a pas fait en sorte d'améliorer la rentabilité *a posteriori* de ce marché.

[329] L'UC et OC soulignent que la correction de l'interfinancement et la rentabilité du marché résidentiel sont des enjeux distincts qui doivent être traités séparément.

[330] En audience, Gaz Métro indique que la correction de l'interfinancement ne devrait pas être guidée par une volonté d'améliorer la rentabilité du développement résidentiel.

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134 Pièce B-0354, page 51.

Le distributeur indique que sa demande de corriger l'interfinancement vise à rapprocher les revenus des coûts. Il précise toutefois qu'une correction à l'interfinancement affecte inévitablement la rentabilité du plan de développement résidentiel et qu'il a établi le niveau de correction proposé à partir de l'objectif de rentabilité visé pour ce plan[135].

[331] L'UC demande de rejeter la proposition de correction de l'interfinancement de Gaz Métro. L'intervenante indique que le taux d'interfinancement du premier palier du tarif D_1 s'est stabilisé et s'est même amélioré au cours des dernières années. Elle soutient également que la demande de Gaz Métro ne respecte pas l'article 7.2 du Mécanisme.

[332] OC recommande d'accepter la proposition de correction de l'interfinancement de Gaz Métro pour l'année tarifaire 2012. L'intervenante précise toutefois que cette recommandation est faite sous réserve du respect des exigences du Mécanisme.

[333] OC souligne, de plus, que sa recommandation ne vaut que pour l'année tarifaire 2012 et que toute demande de correction au cours des prochaines années devrait être analysée au cas par cas.

[334] La Régie note que le taux de rendement interne (TRI) prévisionnel du plan de développement résidentiel 2011-2012 est de 10,1 %, en considérant les nouveaux clients et les ventes en ajout de consommation[136]. Elle constate que ce taux est supérieur à l'objectif de 9,5 % fixé pour le marché résidentiel.

[335] La Régie constate également que le taux d'interfinancement du premier palier du tarif D_1 est demeuré relativement constant au cours des dernières années et s'est même amélioré durant la dernière année[137].

[336] Par ailleurs, la Régie note que le distributeur, dans le cadre de la mise en œuvre de sa vision tarifaire, prévoit aborder l'enjeu de l'interfinancement au tarif D_1 au cours des deux prochaines années[138].

135 Pièce A-0040, pages 81 à 83.
136 Pièce B-0192, Gaz Métro-3, document 2.1, page 3.
137 Pièce B-0191, Gaz Métro-13, document 8.2, page 2.
138 Pièce B-0178, Gaz Métro-13, document 8.1, page 3.

[337] Bien que l'interfinancement au tarif D_1 demeure une préoccupation, la Régie juge qu'il n'y a pas d'urgence à le corriger dès cette année.

[338] **En conséquence, la Régie rejette la proposition de Gaz Métro de corriger l'interfinancement au premier palier du tarif D_1 pour le présent dossier tarifaire.**

4.4.5 VISION TARIFAIRE

[339] Dans le cadre de la décision D-2010-144, la Régie demandait également à Gaz Métro d'examiner les liens entre les résultats de la répartition du coût de service et les structures tarifaires existantes.

[340] Gaz Métro a étudié les liens entre les coûts et les tarifs. Elle est d'avis que les structures des tarifs sont en lien, de façon globale et générale, avec les structures des coûts. Plusieurs constats découlent de cette étude, ce qui incite Gaz Métro à amorcer une réflexion sur certains éléments qui pourraient faire l'objet d'améliorations. Ces constats portent, par exemple, sur les points suivants :

- le premier sous-palier du tarif D_1;
- la répartition des coûts liés à la pointe et des coûts liés au nombre de clients en lien avec la décroissance de prix unitaires moyens que l'on observe aux tarifs D_3 et D_4;
- le niveau de la portion fixe du tarif D_5 via l'obligation minimale annuelle (OMA);
- l'effet de la méthode d'allocation des capacités attribuées et utilisées (CAU) sur la définition des portions fixes et variables des coûts;
- la dégressivité irrégulière observée.

[341] Gaz Métro a entrepris une réflexion visant à développer une vision tarifaire qui la guiderait sur un horizon de moyen et long termes. Cette vision tarifaire comprend trois éléments, soit l'interfinancement, la portion fixe des coûts de distribution et les liens logiques entre les tarifs et les paliers tarifaires.

[342] Le distributeur se dit préoccupé par le niveau d'interfinancement au premier palier du tarif D_1. Il mentionne que ce niveau est important depuis plus de 10 ans et qu'il ne cesse de s'aggraver. À son avis, cet état de fait constitue une iniquité. Il est également

d'avis que le niveau d'interfinancement doit être réduit afin de permettre l'établissement de tarifs justes et raisonnables. En audience, il mentionne que la correction du niveau d'interfinancement constitue une priorité et qu'il abordera ce sujet lors du prochain dossier tarifaire.

[343] Par ailleurs, le distributeur mentionne que c'est la première fois qu'il effectue une étude de classification. En audience, il précise qu'une analyse plus poussée des coûts soulève des éléments qui peuvent paraître contradictoires et qu'il serait nécessaire de poursuivre la réflexion sur ce sujet[139].

[344] Pour atteindre ces objectifs, Gaz Métro invite la Régie à lui permettre de poursuivre son travail de réflexion avec les intervenants.

[345] OC est d'avis que la correction de l'interfinancement doit être dictée par les principes d'allocation des coûts ainsi que par les principes de tarification. Elle mentionne que cette correction représente seulement un aspect de la tarification et qu'elle doit être prise en compte dans le contexte général de la demande tarifaire sur une base annuelle. Elle recommande qu'à l'intérieur d'une fourchette raisonnable de plus ou moins 20 %[140], toute correction de l'interfinancement soit implantée de manière lente et graduelle.

[346] Pour sa part, l'UC mentionne que lors des séances de travail, peu de temps a été consacré à l'examen des liens entre la répartition des coûts et les structures tarifaires existantes et que la question du niveau d'interfinancement n'a pas été abordée. De l'avis de l'intervenante, la simple tenue d'une journée et demie de séance de travail ne saurait constituer une justification pour amorcer une correction de l'interfinancement, *a fortiori* si aucune détérioration de l'interfinancement n'est constatée.

[347] La Régie prend note de la vision tarifaire à moyen et long termes du distributeur et des pistes de réflexion à venir. Elle constate que cette vision prévoit que plusieurs éléments de la structure tarifaire devront être examinés pour chacun des tarifs. Cependant, elle comprend que la priorité du distributeur demeure la correction de l'interfinancement.

139 Pièce A-0040, page 125, lignes 5 à 15.
140 Pièce C-OC-0013, page 28.

[348] La Régie souligne qu'au cours des 10 dernières années, plusieurs modifications ont été apportées aux structures tarifaires dans le but de régler des problèmes spécifiques :

- fermeture de TCE;
- venue de client cogénération de pointe;
- assouplissement des tarifs;
- fusion des premiers paliers du tarif D_1;
- baisse de la redevance d'abonnement au tarif D_1, suivie d'une hausse de la redevance d'abonnement au même tarif.

[349] Bien que ces modifications aient permis, de manière ponctuelle, de régler les problèmes identifiés, elles ont aussi causé des distorsions à d'autres niveaux, dont notamment, les liens entre les tarifs, comme le mentionnent Gaz Métro et la Régie en phase 1 du présent dossier[141].

[350] Chacune des modifications tarifaires affecte et modifie parfois de façon importante la facture des clients. La Régie a le devoir d'approuver des structures tarifaires justes, équitables, simples et qui reflètent la réalité des coûts. La Régie apprécie dans sa globalité les tarifs et leurs structures et doit s'assurer que les modifications qu'elle autorise ne créent pas d'instabilité inutile et temporaire sur la facture de l'ensemble des clients.

[351] La Régie juge prématuré de s'attaquer prioritairement à la correction de l'interfinancement, alors que l'ensemble des structures tarifaires présente des problèmes soulevés tant par Gaz Métro que par les intervenants et la Régie.

[352] Dans un premier temps, la Régie considère important de s'assurer que les structures tarifaires en place soient toujours adéquates. Elle doit également s'assurer que les différents tarifs et sous-paliers regroupent bien les bonnes catégories de clients, en fonction de caractéristiques de coûts et de profil de consommation similaires. La Régie ne retrouve pas au présent dossier l'analyse détaillée des coûts classifiés, de la segmentation de la clientèle et de l'arrimage des coûts avec les tarifs.

[141] Décision D-2011-035.

[353] Le point de départ d'une vision tarifaire doit reposer sur une analyse approfondie des coûts classifiés tels que déposés, pour la première fois, par le distributeur dans le cadre du présent dossier. La Régie juge que cette analyse devrait porter non seulement sur l'examen des coûts fixes et variables, mais aussi sur les coûts unitaires par client, par volume consommé et par CU.

[354] Par la suite, sur la base des résultats identifiés, une analyse minutieuse des liens entre les coûts et les structures des tarifs devrait être effectuée. Des modifications aux structures tarifaires pourront alors être envisagées, accompagnées, au besoin, de mesures transitoires.

[355] Par ailleurs, la Régie demande au distributeur de poursuivre sa réflexion sur la question de l'interfinancement. Cependant, lors de cette réflexion, Gaz Métro devra notamment prendre en compte les niveaux de risque de chacune des catégories tarifaires, la capacité des clients à absorber des hausses tarifaires, la situation concurrentielle et toute autre considération relative au fait que les tarifs doivent refléter plus ou moins parfaitement les coûts. Cette réflexion devra aussi aborder les niveaux d'interfinancement souhaitables entre les différents paliers d'un même tarif.

[356] **Pour l'ensemble de ces motifs, la Régie demande à Gaz Métro de compléter sa vision tarifaire, en y incluant les éléments suivants :**

- **une analyse plus poussée de l'étude de classification des coûts qui se penchera, notamment, sur :**
  - **l'examen de la segmentation de la clientèle,**
  - **l'examen du comportement des coûts unitaires en $/client et en ¢/m³,**
  - **l'examen de la situation des coûts relatifs au CU;**
- **le lien entre les analyses de coûts classifiés et les structures tarifaires existantes;**
- **les modifications tarifaires requises accompagnées, si nécessaire, de mesures transitoires;**
- **une réflexion sur les niveaux acceptables d'interfinancement par catégorie tarifaire;**
- **un plan d'action visant à atteindre des niveaux acceptables d'interfinancement.**

[357] Au besoin, la Régie encourage Gaz Métro à recourir aux services d'un expert en tarification pour la préparation de ces analyses, afin de s'inspirer des meilleures pratiques chez les autres distributeurs.

[358] **Les résultats devront être présentés dans le cadre d'un groupe de travail, auquel participera le personnel technique de la Régie.**

[359] **Pour le prochain dossier tarifaire, Gaz Métro devra déposer un rapport d'état d'avancement et proposer un calendrier de réalisation.**

4.5 *CONDITIONS DE SERVICE ET TARIF*

[360] Gaz Métro propose des modifications au texte des *Conditions de service et Tarif*[142].

[361] La Régie s'est penchée spécifiquement sur les suivis de décisions[143].

4.5.1 CONTRAT PRÉSUMÉ

[362] Faisant suite à la décision D-2010-144, la Régie, dans sa décision D-2011-048, demandait à Gaz Métro d'expliquer si l'utilisation du service de distribution de gaz naturel était nécessaire pour qu'un contrat présumé intervienne entre l'occupant d'un local et le distributeur.

[363] Gaz Métro indique dans sa preuve qu'il y a « utilisation » du service de gaz naturel par le simple fait que ce service est rendu disponible à l'occupant[144]. Par conséquent, il n'est pas nécessaire, selon Gaz Métro, qu'il y ait consommation de gaz naturel pour qu'un contrat se forme entre l'occupant d'un local et Gaz Métro.

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142 Pièce B-0355, sections 1, 2 et 4.
143 Pièce B-0355, section 3.
144 Pièce B-0355.

[364] Selon Gaz Métro, le seul fait que l’occupant puisse bénéficier du service de gaz naturel au moment précis où il en a besoin, sans préavis et sans délai d’alimentation, a pour corollaire la responsabilité de l’occupant de payer les tarifs et les frais associés au maintien de la disponibilité du service, jusqu’à ce qu’il informe Gaz Métro qu’il ne souhaite plus en bénéficier. Sur réception d’un tel avis, Gaz Métro interrompt la disponibilité du service de gaz naturel.

[365] Gaz Métro est d’avis que les frais relatifs au maintien du service de gaz naturel doivent être assumés par le bénéficiaire, soit l’occupant, et non par l’ensemble de la clientèle. Elle est d’avis que le texte actuel de l’article 4.5.2[145] des *Conditions de service et Tarif* reconnaît l’existence d’un contrat présumé sans qu’il y ait consommation de gaz naturel à l’adresse de service, le tout conformément aux exigences du *Code civil du Québec* (C.c.Q.)[146] et des caractéristiques propres du contrat réglementé.

[366] En réponse à une question[147] de la Régie portant sur le nombre de cas où le nouveau résident du local pour lequel le gaz naturel est disponible ne consomme aucun gaz naturel pour une période supérieure à un mois parmi les 30 400 déménagements annuels de clients résidentiels de Gaz Métro, celle-ci indique que cette information n’est pas disponible dans les rapports de gestion usuels et qu’elle n’est donc pas en mesure de la quantifier.

[367] L’UC indique partager l’avis de Gaz Métro selon lequel les frais de base doivent être payés en tout temps lorsque le service de gaz naturel est actif et dessert un local. L’intervenante est préoccupée par le fait que Gaz Métro ne percevrait pas certaines sommes qui lui sont dues, faisant face ainsi à un manque à gagner, si minime soit-il, lorsque des locaux sont vacants ou présumés vacants, la présence et l’identité de l’occupant étant inconnues de Gaz Métro. L’UC ajoute que la perception des frais de base

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145 « ***4.5.2.*** *Le contrat est formé lorsque le distributeur informe le nouveau client qu’il accepte sa demande de service de gaz naturel.*

En l’absence de demande de service de gaz naturel, l’occupant est présumé avoir conclu un contrat à partir du moment où il commence à occuper l’adresse de service où le gaz naturel est mis à sa disposition.

Lorsque la fin d’un contrat avec un client est survenue et qu’aucun contrat n’a été formé, pour l’adresse de service, avec un nouveau client, le propriétaire de l’immeuble où est située l’adresse de service est présumé avoir conclu un contrat et ce, lorsqu’il fait défaut d’informer le distributeur de ses intentions quant au service de gaz naturel dans les 12 jours ouvrables suivant la transmission par le distributeur d’un avis écrit à cet effet. »

146 L.Q. 1991, c. 64.

147 Pièce B-0178, Gaz Métro-3, document 3.1, page 4.

par compteur est incertaine pour environ 2,5 % de l'ensemble de la clientèle résidentielle (environ 5 600 locaux).

[368] Toutefois, l'UC mentionne que le simple fait que le gaz naturel soit disponible ne constitue pas une utilisation et, conséquemment, un contrat présumé. Selon l'intervenante, pour qu'il y ait utilisation, il faut qu'il y ait un geste actif de la part de l'utilisateur du service de gaz naturel et on ne peut présumer de l'existence d'une telle action volontaire du seul fait qu'une personne emménage dans un local.

[369] Selon l'UC, en vertu de l'article 1910[148] C.c.Q., il appartient au propriétaire de délivrer un immeuble en bon état d'habitabilité, c'est-à-dire où les installations fonctionnent. Il appartient également au propriétaire d'informer les locataires, ou les occupants de l'immeuble, des services dont il ne peut ignorer l'existence. L'acceptation du contrat présumé est donc facilement démontrée avec le propriétaire. L'intervenante propose que les *Conditions de service et Tarif* soient modifiés afin de s'assurer que le propriétaire d'un immeuble demeure l'ultime responsable du service de gaz naturel, tant et aussi longtemps qu'il ne met pas fin à ce service.

[370] L'UC demande à la Régie d'ordonner à Gaz Métro de proposer des modifications aux *Conditions de service et Tarif*, telles que celles qu'elle suggère, et qui s'inspirent des conditions de service d'Hydro-Québec, afin que le propriétaire assume la responsabilité du service de gaz naturel lorsque son immeuble est vacant ou présumé vacant par Gaz Métro, aucun occupant ne s'étant déclaré responsable du service de gaz naturel.

[371] La Régie est d'avis que les montants liés à des redevances non versées sont minimes et que cette situation n'est susceptible de survenir, principalement, que pendant la période où les déménagements sont nombreux, soit en juillet, août et septembre. Elle constate qu'il est impossible pour Gaz Métro de chiffrer ces pertes. Lors de l'audience, Gaz Métro indique faire un *blitz* en septembre afin de retracer les occupants inconnus ou, en cas de vacance d'un local, le propriétaire de l'immeuble, réduisant ainsi le montant de base non perçu par compteur. La Régie est d'avis que la préoccupation de l'UC et de Gaz Métro relative à des sommes dues et qui ne seraient pas perçues en raison de l'impossibilité de retracer certains occupants de locaux n'est pas un enjeu majeur.

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[148] « ***1910.*** *Le locateur est tenu de délivrer un logement en bon état d'habitabilité; il est aussi tenu de le maintenir ainsi pendant toute la durée du bail*

La stipulation par laquelle le locataire reconnaît que le logement est en bon état d'habitabilité est sans effet. »

[372] Contrairement à ce que Gaz Métro soutient, la Régie est d'avis que le simple fait que le service de gaz naturel soit mis à la disposition de l'occupant d'un local, sans aucun retrait de gaz naturel, ne peut mener à une présomption de relation contractuelle.

[373] En effet, pour qu'il y ait formation d'un contrat, il doit y avoir manifestation expresse ou tacite de la volonté de contracter (article 1386 C.c.Q.)[149]. Or, la Régie est d'avis que le seul fait d'habiter un local pour lequel le service de gaz naturel est disponible ne constitue ni l'expression tacite, ni l'expression expresse de la volonté de l'occupant d'être lié contractuellement à Gaz Métro. Ceci est d'autant plus évident lorsque le gaz naturel ne sert qu'à l'alimentation de périphériques, comme un barbecue ou un foyer au gaz naturel. Dans ces cas, il est possible que l'occupant ignore que son logement est relié au service de gaz naturel.

[374] Aux fins de l'existence d'un contrat présumé, la Régie est d'avis que la manifestation de la volonté de contracter avec Gaz Métro doit minimalement émaner d'une utilisation du gaz naturel mis à la disposition de l'occupant.

[375] La Régie juge qu'il serait davantage équitable et conforme au droit que le propriétaire soit l'ultime responsable du compte d'un local vacant ou, encore, d'un local dont l'occupant est inconnu de Gaz Métro.

[376] **La Régie demande donc à Gaz Métro de lui soumettre, le 7 décembre 2011 à 12 h, une proposition de modification de l'article 4.5.2 des *Conditions de service et Tarif* afin que l'ultime responsabilité du service de gaz naturel,** d'un local vacant ou, encore, d'un local dont l'occupant est inconnu de Gaz Métro, **soit assumée par le propriétaire de l'immeuble desservi par le gaz naturel.**

4.5.2 UTILISATION DU MOT « CONTRAT »

[377] La Régie est d'avis que l'analyse de Gaz Métro, présentée à la pièce B-0355, annexe A, relativement à l'utilisation du mot « contrat », répond au suivi demandé à la décision D-2010-100.

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149 « ***1386*** *L'échange de consentement se réalise par la manifestation, expresse ou tacite, de la volonté d'une personne d'accepter l'offre de contracter que lui fait une autre personne*. »

[378] **La Régie approuve également les modifications proposées par Gaz Métro aux articles 4.5.1 et 16.1.1 ainsi qu'au 2e alinéa de l'article 18.2.2 du texte des *Conditions de service et Tarif*.**

4.5.3 DÉFINITION DU MOT « JOUR »

[379] **La Régie est satisfaite des explications apportées par Gaz Métro relativement à ce suivi demandé à la décision D-2011-048. Par ailleurs, la Régie approuve la proposition de modification à la définition du mot « jour » ainsi que la définition de « jour ouvrable ».**

4.5.4 DÉFINITIONS DES NOTIONS DE « BRANCHEMENT » ET DE « POINT DE RACCORDEMENT »

[380] Gaz Métro, en réponse à un suivi demandé à la décision D-2011-048, propose de modifier le titre des articles 4.3.3 et 17.1.1.2 comme suit : « frais pour raccordement non standard ». Gaz Métro propose également de remplacer le libellé de l'article 4.3.3 par le suivant :

> « *Les frais prévus à l'article 17.1.1.2 sont exigée du demandeur pour le raccordement d'une adresse de service :*
>
> *Lorsque le point de raccordement est situé à une distance de plus de 3 mètres du coin de la façade de celle-ci; ou*
>
> *Lorsque la longueur du branchement entre la ligne de propriété du terrain, sur lequel est située la bâtisse, et le point de raccordement excède 50 mètres linéaires*[150]. »

[381] **La Régie est satisfaite de la réponse de Gaz Métro à ce suivi. La Régie approuve également les propositions de modification déposées par Gaz Métro relativement aux articles 4.3.3 et 17.1.1.2.**

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[150] Pièce B-0355, page 33.

[382] **Par ailleurs, la Régie accepte l'ensemble des modifications au texte des *Conditions de service et Tarif* proposé par Gaz Métro aux sections 1, 2 et 4 de la pièce B-0355.**

4.5.5 SEUIL D'ACCÈS À L'ÉQUILIBRAGE PERSONNALISÉ

[383] L'abolition du tarif D_M et les modifications au calcul du service de l'équilibrage pour les clients consommant plus de 75 000 m^3/an au tarif D_1 impliquent l'établissement de modalités de gestion d'un seuil d'accès.

[384] Le distributeur propose de maintenir l'application d'un seuil annuel ferme de 75 000 m³/an pour l'établissement du calcul du prix d'équilibrage au 1er octobre 2012.

[385] Il indique que les clients dont la consommation annuelle est près du volume annuel de « transition » pourraient se voir facturer une année selon le taux moyen et une autre année selon leur profil individuel de consommation. Il précise que l'impact de ce changement sur le tarif payé par le client pourrait être important dans le cas des clients dont le profil est saisonnier et des clients ayant un CU élevé.

[386] Le distributeur mentionne avoir examiné des aménagements pour minimiser les impacts, mais que, peu importe la solution envisagée, deux inconvénients subsistent, soit un alourdissement des systèmes de facturation et un traitement inéquitable de certains clients.

[387] En réponse à une demande de renseignements de la Régie, Gaz Métro indique que 854 clients ont des consommations prévues de 70 000 à 80 000 m^3/an pour 2011-2012. Elle précise que, de ce nombre, 446 subiraient un impact tarifaire de moins de 1 ¢/m^3 s'ils passaient le seuil de 75 000 m^3/an[151].

[388] En réponse à une demande de renseignements de la FCEI, le distributeur présente le nombre de clients dont la consommation annuelle a traversé le seuil de 75 000 m^3 au cours des cinq dernières années, réparti selon le nombre d'occurrences. Ces chiffres

[151] Pièce B-0178, Gaz Métro-14, document 1.1, page 2.

montrent que plus de 3 000 clients ont vu leur consommation augmenter au-delà ou descendre en deçà du seuil, au moins une fois depuis cinq ans[152].

[389] En audience, Gaz Métro indique que le seuil de 75 000 m^3/an qu'elle propose n'est pas normalisé et que la rigueur de l'hiver pourrait avoir un impact sur le nombre de clients qui accèdent ou perdent le droit au tarif d'équilibrage personnalisé.

[390] La FCEI estime qu'environ 800 clients pourraient subir, d'année en année, des impacts monétaires importants si la proposition de Gaz Métro était mise en place[153]. Elle demande que le distributeur soumette, dans le cadre du dossier tarifaire 2013, des solutions permettant de limiter la problématique des chevauchements du seuil de 75 000 m^3. Elle demande également que, pour l'année tarifaire 2012, les clients ayant présentement accès au tarif individuel conservent le droit à ce mode de tarification.

[391] La Régie constate que le nombre de clients qui pourraient subir un impact tarifaire significatif est de plusieurs centaines. Même si, dans les faits, l'application d'un seuil ferme de 75 000 m^3/an ne signifie pas que tous les clients susceptibles d'être affectés le seront année après année, elle juge que la portion de clients affectée serait non négligeable.

[392] **La Régie demande à Gaz Métro d'analyser plus à fond la problématique du seuil d'accès et de proposer une solution permettant de minimiser les impacts pour les clients dans le cadre du prochain dossier tarifaire. Elle lui demande également de maintenir le droit au tarif personnalisé aux clients bénéficiant de ce droit au 30 septembre 2011.**

4.5.6 VERSION ANGLAISE DES *CONDITIONS DE SERVICE ET TARIF*

[393] Gaz Métro soumet ses commentaires[154] relativement aux suggestions du réviseur et indique être d'accord avec l'ensemble de ces suggestions, sous réserve de quelques commentaires relatifs aux articles 6.1.1, 7.2.2, 8.4, 11.3.2, 18.2.1, 18.2.2, et 18.2.10.

152 Pièce B-0184, Gaz Métro-14, document 1.4, page 1.
153 Pièce A-0059, pages 89 et 90.
154 Pièce B-0363.

[394] **La Régie accueille l'ensemble des commentaires soumis par Gaz Métro le 17 novembre 2011 relativement aux suggestions du réviseur[155] et lui demande de les intégrer à la version anglaise qu'elle devra soumettre au plus tard le 7 décembre 2011 à 12 h.**

4.6 STRATÉGIE DE GESTION DES ACTIFS

[395] Dans sa décision D-2009-010[156], la Régie prenait acte de l'intention de Gaz Métro de poursuivre le développement de l'approche de gestion des actifs et de l'intégrité des réseaux déjà amorcée, afin d'assurer la sécurité et la pérennité de ses installations. Elle exprimait cependant sa préoccupation quant à la période de développement prévue pour cette approche. Elle demandait à Gaz Métro de faire le point, lors du dossier tarifaire 2011, sur cette approche de gestion des actifs et sur les actions réalisées et à venir.

[396] Dans sa décision D-2010-144, la Régie prenait acte de l'état de développement de la Stratégie de gestion des actifs et demandait à Gaz Métro de déposer, dans le cadre du dossier tarifaire 2012, une mise à jour du document faisant le point, entre autres, sur la grille de priorisation utilisée dans la gestion des risques de même qu'un échéancier plus précis et une évaluation des coûts anticipés pour les prochaines années.

[397] Dans le cadre du présent dossier tarifaire, Gaz Métro soumet, sous pli confidentiel, un rapport présentant l'état d'avancement de la Stratégie de gestion des actifs. Les grandes lignes de la stratégie avaient été arrêtées au moment du dossier tarifaire 2011, mais un certain nombre de processus ont été élaborés et mis en place au cours de la dernière année. Notamment, une réflexion a été amorcée quant à la présentation d'un plan pluriannuel touchant les investissements qui seront requis durant les cinq prochaines années. Un exemple du plan est fourni à titre informatif seulement.

[398] La Régie prend acte de l'état de développement de la Stratégie de gestion des actifs. Elle constate que le plan pluriannuel présente un échéancier des investissements avec une estimation des coûts à titre informatif seulement. Ainsi, l'état actuel du

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155 Pièce A-0069.

156 Dossier R-3681-2008, Demande afin d'obtenir l'autorisation de la Régie pour réaliser la réfection d'une conduite principale à Senneville.

développement de la Stratégie de gestion des actifs ne répond pas entièrement à la demande de la Régie exprimée dans sa décision D-2010-144[157].

[399] La Régie reconnaît le caractère évolutif de la Stratégie de gestion des actifs. Elle demande à Gaz Métro, dans le cadre du dossier tarifaire 2013, un rapport complet présentant la Stratégie de gestion des actifs, incluant un échéancier, une évaluation des coûts totaux et des coûts anticipés pour les prochaines années.

[400] Afin de favoriser un allégement de la procédure, la Régie demande à Gaz Métro de limiter les éléments d'informations qui devront être traités de façon confidentielle.

4.7 FONDS EN EFFICACITÉ ÉNERGÉTIQUE (FEÉ)

4.7.1 SUIVI 2011

[401] Au cours des cinq premiers mois de l'année financière 2011, le FEÉ a dépensé environ 1,2 M$, soit 30 % du budget autorisé par la Régie. Les économies d'énergie réalisées correspondent, quant à elles, à un peu plus de 28 % des objectifs pour 2011. Tenant compte du taux d'opportunisme appliqué, les résultats obtenus par le FEÉ sont similaires aux résultats obtenus pour la même période en 2010. Le FEÉ croit qu'il sera en mesure d'atteindre ses objectifs d'économie d'énergie comme il l'a fait en 2010 et prévoit que le nombre de participants augmentera plus rapidement au cours des sept derniers mois de son exercice financier[158].

4.7.2 OBJECTIF D'ÉCONOMIE D'ÉNERGIE ET BUDGET DEMANDÉ EN 2012

[402] Le Plan d'action 2012 du FEÉ présente des prévisions pour un an plutôt que trois, pour tenir compte de la décision D-2010-116 dans laquelle la Régie précisait que le FEÉ cessera ses activités le 30 septembre 2012[159].

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157 Décision D-2010-144, dossier R-3720-2010 Phase 2, page 54.
158 Pièce B-0060, pages 4 et 5.
159 Décision D-2010-116, dossier R-3693-2009, page 35; pièce B-0061, page 6.

[403] Le Plan d'action 2012 du FEÉ propose des investissements de près de 4,2 M$ pour mettre en œuvre 10 programmes qui génèreront des économies de près de 2,2 Mm³ de gaz naturel par année[160].

[404] La Régie constate que le budget demandé est supérieur au budget de 3,9 M$ autorisé pour 2011. Cependant, plus de 82 % du budget demandé est associé à l'aide financière directe des programmes. La Régie note également que des modifications importantes ont été apportées aux modalités d'aide financière des programmes du FEÉ en 2011 et que l'impact de ces changements est plus significatif en 2012 qu'en 2011[161]. Une partie de l'augmentation de budget observée en 2012 découle donc de décisions antérieures de la Régie. **En conséquence, la Régie approuve le budget 2012 du FEÉ.**

4.7.3 SUIVI DE DÉCISIONS ANTÉRIEURES

[405] En suivi de la décision D-2010-144, le FEÉ applique les taux d'opportunisme autorisés pour le PR330-Rabais à l'achat de fenêtres certifiées ENERGY STAR® et le PC420-Aide financière à la rénovation éconergétique de l'enveloppe des bâtiments. Il maintient la valeur des jetons de présence versés aux membres du Comité de gestion (COGE) à 500 $, en plus de demander le remboursement des sommes versées en trop aux membres du COGE entre le 1er octobre et le 4 novembre 2010[162].

[406] **La Régie considère que ces actions répondent adéquatement aux demandes contenues à la décision D-2010-144**.

[407] Dans la décision D-2010-116, la Régie demandait au groupe de travail responsable de la négociation du prochain mécanisme incitatif à l'amélioration de la performance de Gaz Métro de soumettre, à la fin de celui-ci et dans le cadre du dossier tarifaire 2012, un plan d'action prévoyant la dissolution du FEÉ. Ce plan devait inclure les règles applicables à la réallocation du solde du FEÉ aux clients y ayant contribué ainsi qu'une proposition relative au transfert de certains programmes au PGEÉ[163].

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160 Pièce B-0061, page 4.
161 Décision D-2010-144, dossier R-3720-2010 Phase 2, page 60; pièce B-0061, page 31, tableau 2 : l'aide financière correspond à plus de 3,4 M$ en 2012; pièce B-0061, page 7.
162 Décision D-2010-144, dossier R-3720-2010 Phase 2, pages 61 et 62; pièce B-0061, page 8.
163 Décision D-2010-116, dossier R-3693-2009, page 35.

[408] En avril 2011, Gaz Métro informe la Régie que le Groupe de travail « *n'est pas encore parvenu à une position à ce sujet*[164] ». Le distributeur dépose cependant, en audience, un extrait de la proposition relative au plan d'action en vue de la dissolution du FEÉ. Selon Gaz Métro, ce document fait état du processus qui doit être mis en place au cours des prochains mois en vue de la dissolution du FEÉ au 30 septembre 2012[165].

[409] Le FEÉ indique, pour sa part, que des travaux d'analyse sont en cours afin d'identifier le potentiel d'intégration de ses programmes au PGEÉ[166].

[410] L'UC demeure préoccupée par le fait que les négociations du Groupe de travail ne puissent être conclues en temps opportun pour que les modalités de dissolution du FEÉ soient examinées dans le cadre du présent dossier tarifaire[167]. L'intervenante demande à la Régie de déterminer un calendrier de transfert des programmes du FEÉ au PGEÉ ainsi qu'une date de tombée pour la disposition du solde, faisant valoir que « *si on tarde trop,* […] *on va s'éloigner de plus en plus de cette équité intergénérationnelle puisque les clients qui pourraient bénéficier du retour du solde ne seront plus les clients qui ont contribué au FEÉ*[168] ».

[411] **La Régie prend acte de l'état d'avancement du dossier R-3693-2009 en ce qui a trait au plan d'action sur la dissolution du FEÉ.** Cependant, la Régie considère que l'établissement du calendrier de transfert des programmes du FEÉ au PGEÉ ainsi que la date de tombée pour la disposition du solde du FEÉ ne relèvent pas du présent dossier.

4.7.4 PROGRAMMES DU FEÉ

[412] La Régie note que, pour 2012, le FEÉ prévoit reconduire tous ses programmes sans changement, à l'exception de l'activité Nouvelles technologies pour laquelle il n'accepte plus de nouvelles demandes et ne fait plus de promotion depuis le 28 février 2011[169].

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164 Pièce B-0062, page 2.
165 Pièce B-0265; pièce A-0059, pages 74 et 75.
166 Pièce B-0178, Gaz Métro-9, document 7.1, pages 1 et 2.
167 Pièce C-UC-0017, pages 17 à 19.
168 Pièce A-0059, pages 206 à 209.
169 Pièce B-0061, pages 4 à 7.

[413] La Régie note également que pour établir la consommation et le cas-type des participants au PFR160-Aide financière à l'achat d'un système de récupération de la chaleur des eaux de drainage (RCED) pour les MFR, le FEÉ a utilisé les mêmes données que pour le programme résidentiel PR340-Aide financière à l'achat d'un système de RCED[170]. Or, en établissant le cas-type du PFR160, qui vise pourtant les MFR, le FEÉ a utilisé la même proportion de propriétaires d'unifamiliale, de duplex et de triplex que pour l'ensemble de la clientèle résidentielle de Gaz Métro, sans vérifier que cette proportion était adéquate.

[414] **La Régie demande donc, advenant le transfert du PFR160 au PGEÉ, que le cas-type du programme soit ajusté pour tenir compte du fait qu'il vise une clientèle de MFR.**

4.7.5 RENTABILITÉ

[415] **Par souci d'uniformité de traitement entre le PGEÉ et le FEÉ, la Régie autorise, pour 2012, un taux d'actualisation réel uniforme de 4,53 % aux fins du calcul de la rentabilité des programmes du FEÉ, tel que proposé par Gaz Métro**[171].

[416] Par ailleurs, jugeant que cet ajustement est requis pour éviter une surévaluation de la rentabilité, **la Régie prend acte de la correction apportée à la méthode de calcul du TP, afin de tenir compte des coûts incrémentaux complets des mesures du Plan d'action 2012 du FEÉ**.

4.7.6 ÉVALUATION

[417] La Régie note que le FEÉ a suspendu, en 2011, les évaluations du PS151-Système de préchauffage solaire de l'air ou de l'eau dans les bâtiments à vocation sociocommunautaire et du PC440-Système de préchauffage solaire de l'air ou de l'eau ainsi que de l'activité Nouvelles technologies. **La Régie prend acte de la suspension**

170 Pièce B-0178, Gaz Métro-9, document 8.1, page 1.
171 Pièce B-0156, pages 16 et 17; pièce B-0207, page 9.

définitive de l'évaluation de ces programmes et activité ainsi que celle du PR330, prévue pour 2012[172].

4.8 ÉVALUATION DU PROGRAMME DE RABAIS À LA CONSOMMATION (PRC) ET DU PROGRAMME DE RÉTENTION PAR VOIE DE RABAIS À LA CONSOMMATION (PRRC)

[418] Dans le cadre du dossier tarifaire 2010 (dossier R-3690-2009), le groupe de travail constatait, dans son rapport à la Régie, qu'il était justifié d'évaluer les programmes commerciaux PRC et PRRC, compte tenu des montants relativement importants alloués à ces programmes.

[419] Dans ce même rapport, Gaz Métro indiquait son intention de déposer un rapport d'évaluation de ces programmes dans le cadre du dossier tarifaire 2011. Le distributeur précisait que ce rapport inclurait, notamment, des évaluations des taux d'opportunisme, des ratios coûts/bénéfices et du déploiement des programmes dans les différents marchés. La Régie prenait acte de cette intention dans la décision D-2009-156[173].

[420] Dans sa décision D-2010-144[174], la Régie acceptait de reporter le dépôt du rapport d'évaluation au dossier tarifaire 2012.

[421] Dans le cadre du présent dossier, Gaz Métro dépose un rapport d'évaluation des programmes PRC et PRRC préparé à partir des résultats d'une étude de marché réalisée par la firme Abscisse Recherche.

[422] La Régie constate que l'évaluation ne couvre que l'aspect marché et ne comporte aucune évaluation de la performance économique des deux programmes au cours des dernières années.

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172 Pièce B-0061, pages 23 et 24.
173 Décision D-2009-156, dossier R-3690-2009, page 12.
174 Décision D-2010-144, dossier R-3720-2010 Phase 2, page 62.

[423] En audience, le distributeur indique ne pas s’être limité à une analyse de marché et précise avoir également examiné ses données internes et procédé à une évaluation de l’impact tarifaire que pourrait avoir une diminution des aides financières[175].

[424] La Régie note que, pour le secteur de la nouvelle construction résidentielle, les aides financières ne sont pas établies en fonction de la rentabilité pour le client, mais en fonction du coût des équipements.

[425] Le distributeur mentionne que, pour le secteur résidentiel, le coût de l’énergie n’est pas un critère important dans le choix de l’équipement. Il explique que, considérant qu’environ 85 % des nouvelles ventes résidentielles sont faites en nouvelle construction et que la majorité des projets sont réalisés par des constructeurs promoteurs, les subventions PRC, sont surtout versées à ces derniers[176]. Il précise que ceux-ci n’étant pas les propriétaires finaux de l’immeuble, ils ne bénéficient pas de la rentabilité liée à la position concurrentielle du gaz naturel et cherchent simplement à minimiser le coût de l’équipement pour rester compétitif dans le marché de la construction.

[426] Gaz Métro soumet que la position concurrentielle du gaz naturel permet d’avoir plus de conversions et peut amener plus d’intérêt pour le gaz naturel, mais elle n’a pas d’impact sur la rentabilité pour le constructeur, laquelle dépend directement du PRC. Abaisser le PRC, parce que la situation concurrentielle du gaz naturel est meilleure, amènerait rapidement une baisse assez importante des nouvelles ventes[177].

[427] Dans le cadre du dossier R-3630-2007, Gaz Métro présentait un plan d’ajustement des aides financières qui prévoyait une baisse des subventions du PRC pour le secteur résidentiel au cours des années 2007 et 2008. Le distributeur justifiait ces baisses par l’amélioration de la position concurrentielle du gaz naturel :

> « *La hausse du prix du mazout et les augmentations des tarifs d’électricité depuis 2004, combinées à la baisse du prix moyen du gaz naturel en 2007, positionnent le gaz naturel en 2007 dans une situation concurrentielle plus favorable que lors des années antérieures. De plus, la croissance du taux de pénétration du gaz naturel dans le marché résidentiel depuis 2001 indique que le gaz naturel est de plus en plus populaire auprès des clients du marché résidentiel.*

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175 Pièce A-0045, page 84.
176 Pièce A-0045, pages 70 et 71.
177 Pièce A-0045, page 53.

Ces changements, dans le contexte du marché résidentiel, ont permis un réajustement à la baisse des subventions (PRC), autant pour la nouvelle construction que pour la conversion sur réseau afin de les calibrer en fonction de la situation concurrentielle. Pour la nouvelle construction résidentielle, le plan mis en place en novembre 2006 prévoit une réduction des subventions moyennes de 2 % pour 2007 et de 3 % pour 2008. Le plan d'ajustement sera calibré à nouveau en fonction du contexte concurrentiel pour les années suivantes. Pour le marché de la conversion, le montant de subvention moyen par client "chauffage" a été réduit de 500 $ dès septembre 2006[178]. »

[428] La Régie constate que le rapport d'évaluation ne permet pas d'apprécier l'impact des baisses des subventions en 2007 et 2008 sur la performance des programmes.

[429] Le distributeur indique également que, pour le secteur résidentiel et le petit commercial, c'est la rentabilité du projet (pour le distributeur) qui limite le montant de la subvention. Il précise que, même si les modalités du programme permettent de subventionner 100 % des dépenses admissibles, qui sont le coût de l'équipement et l'installation, cette limite est rarement atteinte[179].

[430] La Régie comprend donc que pour plusieurs projets du secteur résidentiel, le montant de la subvention ramène la rentabilité du projet au seuil requis par le distributeur, soit son coût en capital prospectif. Le rapport ne fournit pas de données sur la rentabilité réelle de ces projets par rapport à leur rentabilité prévisionnelle.

[431] **La Régie prend acte du dépôt, par Gaz Métro, du rapport d'évaluation de marché des PRC et PRRC.** Le rapport d'évaluation permet de voir que les PRC et PRRC sont importants pour le marché. Il ne permet toutefois pas d'apprécier les résultats de ceux-ci au cours des dernières années parce qu'il ne traite pas des résultats réels observés. Le rapport présente une analyse de sensibilité, basée sur un sondage auprès des participants, pour évaluer l'impact sur les ventes et calculer l'impact tarifaire de changements du niveau des subventions par rapport à la situation actuelle, mais n'évalue pas cette situation actuelle.

[432] En réponse à une demande de la Régie, le distributeur indique ne pas être en mesure de produire une analyse de rentabilité réelle des PRC et PRRC pour les années

178 Dossier R-3630-2007, pièce B-15, Gaz Métro-2, document 7, pages 28 et 29.
179 Pièce A-0045, page 88.

2006 à 2010, parce qu'il ne dispose pas des données nécessaires à une telle analyse[180]. Il ajoute que la Régie avait accepté, dans la décision D-2011-073[181], la proposition de Gaz Métro de présenter, à compter du plan de ventes 2009, pour le marché résidentiel, le résultat de l'analyse *a posteriori* du plan de vente à la troisième année ainsi qu'à la sixième année, après la présentation du plan de développement *a priori*.

[433] **Pour pallier aux déficiences de l'évaluation, compte tenu que, comme l'a mentionné Gaz Métro, les données réelles des dernières années ne sont pas disponibles, la Régie lui demande de :**

- **déposer, lors du prochain dossier tarifaire, une analyse à jour des surcoûts des équipements au gaz naturel et des grilles de subventions;**
- **présenter, lors des prochains rapports annuels, un suivi des subventions des PRC et PRRC versées et des volumes prévus liés à ces subventions ainsi que la rentabilité des projets subventionnés, par marché, en distinguant pour le PRC les nouvelles constructions et les conversions;**
- **présenter, lors du rapport annuel 2012, une méthode de suivi *a posteriori* des volumes et de la rentabilité liés aux projets subventionnés similaire au suivi *a posteriori* du plan de développement.**

4.9 TAUX D'AMORTISSEMENT

[434] Dans la décision D-2010-030[182], la Régie jugeait raisonnable de reporter la révision des taux d'amortissement au présent dossier tarifaire.

[435] Dans le cadre du présent dossier, Gaz Métro demande à la Régie d'autoriser les taux d'amortissement qu'elle utilisera à compter du 1er octobre 2011[183]. Elle présente, au soutien de sa demande, l'étude de la firme d'experts Gannett Fleming, laquelle porte sur les immobilisations en service au 30 septembre 2009.

[436] En se basant sur les conclusions de cette étude, le distributeur propose une nouvelle méthode pour la détermination des taux d'amortissement ainsi qu'une révision à

[180] Pièce B-0178, Gaz Métro-3, document 4.2, pages 1 et 2.
[181] Décision D-2011-073, dossier R-3745-2010, page 17.
[182] Dossier R-3720-2010.
[183] Pièce B-0063, page 4.

la baisse du taux moyen d'amortissement pour les actifs de distribution, de stockage et de transmission, se traduisant par une hausse des durées de vie proposées pour ces catégories d'immobilisation.

MÉTHODE

[437] La nouvelle méthode d'amortissement que le distributeur propose de retenir, soit la méthode ELG[184], est plus précise que la méthode ASL[185] utilisée pour les études précédentes. En effet, la méthode ELG tient compte du fait que certains actifs sont retirés avant la fin de leur durée de vie utile. Il en résulte un niveau plus élevé de charge d'amortissement plus tôt dans la vie d'un groupe d'actifs. De plus, cette méthode est conforme à la fois aux IFRS et aux principes comptables généralement reconnus (PCGR) américains, le référentiel comptable que Gaz Métro prévoit adopter à partir du 1er octobre 2012.

[438] L'expert retenu par le distributeur, M. Kennedy, recommande l'utilisation de la méthode ELG car elle conduit à une charge d'amortissement qui reflète mieux la durée d'utilisation des actifs. De plus, il indique que le recours à cette méthode élimine l'iniquité entre les générations de clients découlant de l'utilisation de la méthode ASL.

[439] L'UMQ recommande à la Régie d'accepter la demande d'utilisation de la méthode ELG, tandis que l'UC recommande de la rejeter en faveur du maintien de la méthode ASL. Selon l'UC, il existe deux aspects distincts et indissociables inhérents à l'application de toute politique d'amortissement du capital investi, soit la récupération et la rémunération du capital investi. L'intervenante est d'avis que l'étude d'amortissement produite par l'expert est centrée sur le seul volet récupération du capital, sans égard au volet complémentaire de la rémunération du capital[186].

[440] Selon l'expert Kennedy, une politique d'amortissement ne devrait pas être utilisée pour manipuler le montant de rendement qui sera reconnu pour l'utilité[187].

[441] La Régie est d'avis que la méthode ELG est une méthode plus précise que la méthode ASL, en plus d'être conforme aux PCGR américains. Cette méthode comporte

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[184] *Equal life group* (ELG).
[185] *Average service life* (ASL).
[186] Pièce C-UC-0017, page 13.
[187] Pièce B-0216, page 27.

également l'avantage de constater une charge d'amortissement plus élevée en début de période, ce qui permet de réduire l'accroissement des soldes de déviations futurs. **En conséquence, la Régie approuve l'utilisation de la méthode ELG.**

TAUX

[442] Le distributeur propose de modifier les taux d'amortissement de certains postes.

[443] Les principaux postes d'immobilisation sont les conduites principales (50 % des immobilisations) et les branchements d'immeubles (27 % des immobilisations).

TABLEAU 5

Taux d'amortissement des principaux postes des immobilisations

	Taux proposés	Taux actuels
Conduites principales en acier	2,82 %	3,06 %
Conduites principales en plastique direct	1,98 %	2,21 %
Branchements d'immeubles en acier	2,66 %	3,77 %
Branchements d'immeubles en plastique direct	3,19 %	3,63 %

Source : B-0096, page 11

[444] Selon Gaz Métro, l'étude proposée des taux ne cause pas d'impact significatif sur la charge d'amortissement annuelle projetée pour l'année 2012.

[445] Pour les actifs de distribution en acier, soit les conduites et les branchements, l'expert Kennedy recommande une durée de vie moins élevée que celle résultant des analyses statistiques, en raison de sa politique de modération. Selon cet expert, des changements significatifs à la durée de vie de ces actifs ne sont pas conseillés, car ils pourraient mener à des fluctuations considérables lorsque les causes du changement ne sont pas de nature permanente[188].

[446] Quant aux branchements et conduites en plastique direct, l'expert Kennedy recommande des durées de vie plus élevées que dans le passé. Il soutient que la nouvelle

[188] Pièce B-0193, Gaz Métro-6, document 8.12, page 1.

génération de plastique montre des indications d'une durée de vie plus longue. Ainsi, il est convaincu qu'il n'est pas nécessaire de modérer la hausse de la durée de vie de ces actifs[189].

[447] L'UMQ considère que la politique de modération s'apparente à une politique de report de l'amortissement[190]. Elle s'oppose à la durée de vie proposée de 45 ans pour les branchements d'immeubles en acier et soumet que la durée de vie de cet actif aurait dû être portée au minimum à 50 ans[191], soit la durée de vie statistique.

[448] La Régie considère raisonnables les taux d'amortissement demandés pour les conduites principales et les branchements d'immeubles. Elle constate que Gaz Métro possède des comptes séparés pour les conduites et branchements en plastique et en acier, alors que ce n'est pas le cas pour les distributeurs comparables. Dans ces circonstances, une validation des taux avec les comparables est plus difficile.

[449] **La Régie approuve la modification des taux d'amortissement proposés par Gaz Métro pour les actifs de distribution, de stockage et de transmission.**

[450] Gaz Métro demande des changements visant à maintenir une saine gestion de ses immobilisations. Ces changements se composent majoritairement d'ajouts de catégories relatives aux actifs de stockage (bâtiments et équipements) et aux installations générales.

[451] Gaz Métro a effectué une étude portant sur les installations générales. Dans cette étude, elle constate qu'un changement de taux pour les catégories machinerie lourde et remorques est requis. Celui-ci devrait passer de 10 % à 12,5 %. Le distributeur demande aussi l'ajout d'une catégorie pour l'équipement et l'outillage amortie au taux de 8,33 %. Ces améliorations ont été identifiées par Gaz Métro à la suite de la revue des catégories dans le cadre des analyses sur l'approche par composante. Selon Gaz Métro, ces modifications ont un impact non significatif sur la charge d'amortissement.

[452] **La Régie approuve la création des nouvelles catégories d'immobilisation, la modification des taux d'amortissement applicables à certaines catégories d'immobilisation déjà existantes ainsi que les taux d'amortissement afférents.**

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189 Pièce A-0045, pages 173 et 174.
190 Pièce C-UMQ-0013, page 27.
191 Pièce C-UMQ-0013, pages 25 à 27.

DURÉE DE VIE UTILE DES ACTIFS DU POSTE SENNEVILLE

[453] Dans sa décision D-2011-048, la Régie demandait à Gaz Métro de valider la vie utile des actifs du poste Senneville dans le cadre de la mise à jour de l'étude d'amortissement. Gaz Métro indique que la durée de vie utile des actifs dudit projet est de 50 ans.

[454] **Le résultat de la validation de la vie utile des actifs touchés par le projet Senneville répond au suivi requis.**

[455] **Pour l'ensemble de ces motifs,**

La Régie de l'énergie :

ACCUEILLE partiellement la demande ré-amendée en date du 31 août 2011;

RECONDUIT jusqu'au 30 septembre 2013, le programme de flexibilité tarifaire mazout pour les clients aux tarifs D_1 et D_3;

APPROUVE l'entente intervenue entre les membres du Groupe de travail ainsi que toutes les pièces s'y rapportant;

APPROUVE le budget de 12,3 M$ proposé par le Groupe de travail pour le PGEÉ 2012;

AUTORISE l'utilisation d'un montant de 4,2 M$ provenant des sommes imputées au FEÉ, conformément au Plan d'action 2012 du FEÉ;

APPROUVE le plan d'approvisionnement de Gaz Métro pour l'exercice 2012, tel que prévu à l'article 72 de la Loi, sous réserve des précisions énoncées à la section 4.2.3 de la présente décision;

FIXE un taux de rendement et une structure de capital respectant les paramètres suivants :

- un ratio de dette de 54 %,
- un ratio d'avoir propre de 38,5 %,
- un ratio d'actions privilégiées de 7,50 %,
- un taux de rendement sur l'avoir propre de 8,90 %;

RÉSERVE SA DÉCISION sur la stratégie tarifaire et les grilles tarifaires en découlant pour les tarifs D_1, D_3, D_4 et D_5;

RÉITÈRE les autres conclusions et décisions énoncées dans la présente décision;

DEMANDE à Gaz Métro de déposer, pour approbation, les pièces révisées, la grille tarifaire et les versions française et anglaise du texte des *Conditions de service et Tarif* pour tenir compte de la présente décision, au plus tard le 7 décembre 2011 à 12 h et **RÉSERVE** sa décision à ces égards.

Gilles Boulianne
Régisseur

Marc Turgeon
Régisseur

Jean-François Viau
Régisseur

Représentants :

- Association des consommateurs industriels de gaz (ACIG) représentée par M^{e} Guy Sarault;
- Fédération canadienne de l'entreprise indépendante (section Québec) (FCEI) représentée par M^{e} André Turmel;
- Groupe de recherche appliquée en macroécologie (GRAME) représenté par M^{e} Geneviève Paquet;
- Option consommateurs (OC) représentée par M^{e} Éric David;
- Regroupement des organismes environnementaux en énergie (ROEÉ) représenté par M^{e} Franklin S. Gertler;
- Regroupement national des conseils régionaux de l'environnement du Québec (RNCREQ) représenté par M^{e} Annie Gariépy;
- Société en commandite Gaz Métro (Gaz Métro) représentée par M^{es} Vincent Regnault, Hugo Sigouin-Plasse et Eric Dunberry;
- Stratégies énergétiques et Association québécoise de lutte contre la pollution atmosphérique (S.É./AQLPA) représenté par M^{e} Dominique Neuman;
- TransCanada Energy Ltd (TCE) représentée par M^{e} Pierre Grenier;
- Union des consommateurs (UC) représentée par M^{e} Hélène Sicard;
- Union des municipalités du Québec (UMQ) représentée par M^{e} Steve Cadrin.

ANNEXE 1

Suivis
découlant de la présente décision

Annexe 1 (2 pages)	
G. B.	________
M. T.	________
J.-F. V.	________

LISTE DES SUIVIS REQUIS PAR LA PRÉSENTE DÉCISION

A. LA RÉGIE DEMANDE QUE LES ÉLÉMENTS SUIVANTS SOIENT DÉPOSÉS PAR GAZ MÉTRO LORS DU PROCHAIN DOSSIER TARIFAIRE

1. Proposer, dans le cadre du PGEÉ 2013, une nouvelle approche résidentielle qui optimiserait les contacts avec les participants et assurerait une meilleure rentabilité future à tous les programmes, notamment le PE103.

2. Présenter ses recommandations à l'égard de l'impact énergétique des programmes PE202 et PE210 dans le cadre du PGEÉ 2013.

3. Appliquer un taux de bénévolat de 0 % au PE212 jusqu'à l'obtention des résultats de l'exercice de vérification proposé par le distributeur.

4. Poser une hypothèse documentée et différente de 0 % à l'égard du tendanciel associé aux PE207 et PE211, dans le cadre du PGEÉ 2013.

5. Présenter un suivi sur le travail en cours découlant des pistes de réflexion et d'ajustement proposées lors du dossier tarifaire 2014.

6. Déposer un rapport d'état d'avancement et proposer un calendrier de réalisation visant à compléter la vision tarifaire en y incluant les éléments mentionnés par la Régie. Présenter les résultats dans le cadre d'un groupe de travail auquel participera le personnel technique de la Régie.

7. Analyser plus à fond la problématique du seuil d'accès au tarif d'équilibrage personnalisé pour les clients du tarif D_1 et proposer une solution permettant de minimiser les impacts pour les clients.

8. Déposer une analyse à jour des surcoûts des équipements au gaz naturel et des grilles de subventions des PRC et PRRC.

B. LA RÉGIE DEMANDE QUE LES ÉLÉMENTS SUIVANTS SOIENT DÉPOSÉS PAR GAZ MÉTRO LORS D'UN DOSSIER TARIFAIRE ULTÉRIEUR

1. Présenter les recommandations découlant des pistes de réflexion et d'ajustement proposées lors du dossier tarifaire 2014.

C. LA RÉGIE DEMANDE QUE LES ÉLÉMENTS SUIVANTS SOIENT DÉPOSÉS PAR GAZ MÉTRO LORS DES RAPPORTS ANNUELS

1. Compléter sa réponse quant à la part des économies d'énergie associée au PE207 et au PE211, lors du rapport annuel 2011. La Régie demande également de justifier tout écart majeur entre les objectifs fixés et les résultats observés, pour ces deux programmes.
2. Présenter, lors des rapports annuels à compter du rapport annuel 2011, un suivi des subventions des PRC et PRRC versées et des volumes prévus liés à ces subventions et de la rentabilité des projets subventionnés, par marché, en distinguant pour le PRC les nouvelles constructions et les conversions;
3. Présenter, lors du rapport annuel 2012, une méthode de suivi *a posteriori* des volumes et de la rentabilité liés aux projets subventionnés comme pour le suivi *a posteriori* du plan de développement.

ANNEXE 2

FORMULE D'AJUSTEMENT AUTOMATIQUE DU TAUX DE RENDEMENT SUR L'AVOIR DE L'ACTIONNAIRE DE GAZ MÉTRO POUR L'ANNÉE 2013 ET LES ANNÉES SUBSÉQUENTES

Annexe 2 (3 pages)

G. B. ________

M. T. ________

J.-F. V. ________

FORMULE D'AJUSTEMENT AUTOMATIQUE DU TAUX DE RENDEMENT SUR L'AVOIR DE L'ACTIONNAIRE DE GAZ MÉTRO POUR L'ANNÉE 2013 ET LES ANNÉES SUBSÉQUENTES

Taux de rendement sur l'avoir de l'actionnaire pour l'année témoin t = 8,90 % + 0,75 * ($POCL_t$ – 4,0 %) + 0,5 * ($ECSR_t$ – 1,5 %)

où :

$POCL_t$ = Prévision du taux de rendement des obligations du Canada de long terme pour l'année témoin t.

$ECSR_t$ = Écart de crédit des obligations de long terme des sociétés réglementées canadiennes de cote de crédit A par rapport aux obligations du Canada de long terme pour l'année témoin t.

Le facteur $POCL_t$ est calculé comme suit :

$$POCL_t = \left[\frac{PO_{10}C_{nov,t} + PO_{10}C_{août,t}}{2}\right] + \left[\frac{\sum_i \left(O30 \quad C_{i,t-1} - O_{10}C_{i,t-1}\right)}{I}\right]$$

où :

$PO_{10}C_{nov,t}$ = Prévision du taux de rendement des obligations 10 ans du gouvernement du Canada à la fin du mois de novembre de l'année témoin t-1, telle qu'elle apparaît dans la publication du mois d'août de l'année tarifaire t-1 du Consensus Forecasts.

$PO_{10}C_{août,t}$ = Prévision du taux de rendement des obligations 10 ans du gouvernement du Canada à la fin du mois d'août de l'année témoin t, telle qu'elle apparaît dans la publication du mois d'août de l'année tarifaire t-1 du Consensus Forecasts.

$O_{30}C_{i,t-1}$ = Taux de rendement des obligations 30 ans du gouvernement du Canada à la clôture de chaque journée ouvrable i du mois de juillet de l'année tarifaire t-1 tel que publiés par la Banque du Canada (Cansim Series V39056).

$O_{10}C_{i,t-1}$ = Taux de rendement des obligations 10 ans du gouvernement du Canada à la clôture de chaque journée ouvrable i du mois de juillet de l'année tarifaire t-1 tels que publiés par la Banque du Canada (Cansim Series V39055).

I = Nombre de journées ouvrables dans le mois de juillet de l'année tarifaire t-1 pour lesquelles les taux de rendement des obligations du gouvernement du Canada et les taux de rendement des obligations 30 ans des sociétés réglementées canadiennes de cote de crédit A sont publiés.

Le facteur $ECSR_t$ correspond à la moyenne des écarts de rendement quotidiens entre les obligations 30 ans des sociétés réglementées canadiennes de cote de crédit A et les obligations 30 ans du gouvernement du Canada, constatés chaque journée ouvrable i du mois de juillet de l'année tarifaire t-1. Le facteur $ECSR_t$ est calculé comme suit :

$$ECSR_t = \frac{\sum_i (O_{30}SR_{i,t-1} - O_{30}C_{i,t-1})}{I}$$

où :

$O_{30}SR_{i,t-1}$ = Moyenne quotidienne des taux de rendement des obligations 30 ans des sociétés réglementées canadiennes de cote de crédit A à la clôture de chaque journée ouvrable i du mois de juillet de l'année tarifaire t-1, telle qu'elle apparaît à l'indice C29530Y publié par Bloomberg.

$O_{30}C_{i,t-1}$ = Taux de rendement des obligations 30 ans du gouvernement du Canada à la clôture de chaque journée ouvrable i du mois de juillet de l'année tarifaire t-1 tel que publiés par la Banque du Canada (Cansim Series V39056).

I = Nombre de journées ouvrables dans le mois de juillet de l'année tarifaire t-1 pour lesquelles les taux de rendement des obligations du gouvernement du Canada et les taux de rendement des obligations 30 ans des sociétés réglementées canadiennes de cote de crédit A sont publiés.

ANNEXE 3

Cette annexe est confidentielle

Annexe 3

G. B. ________

M. T. ________

J.-F. V. ________